To: McGartland, Al[McGartland.Al@epa.gov]
Cc: Marten, Alex[Marten.Alex@epa.gov]
From: Evans, DavidA
Sent: Tue 7/28/2015 2:47:36 PM
Subject: FW: Updated version of 111(b) New/Mod/Recon preamble and Reg Text
111b preamble_DRAFT_072415_RLSO_compareto_071015.docx
111b preamble_DRAFT_072415_clean.docx
GHG_EGU_111(b)_Reg_Text_072415.docx

Al,

Here is the b preamble. The sections in the b preamble that I identified in the d preamble I just sent are titled "a. "System[s] of emission reduction ... adequately demonstrated"." and "b. "Best"".

Sections like "H. Consideration of Costs" Ex 5 describes the costs that were considered for establishing the b standards. It has subections entitled "4. Consideration of Capital Costs " "6. Comparison with Monetized Benefits" and "7. Overall Costs and Economic Impacts".

D

From: Elman, Barry
Sent: Friday, July 24, 2015 9:11 PM
To: Beauvais, Joel
Cc: Rennert, Kevin; Evans, DavidA; Marten, Alex
Subject: Fw: Updated version of 111(b) New/Mod/Recon preamble and Reg Text

FYI -- Here's the latest version of the 111(b) preamble and reg text. Just sent to OMB.

From: Culligan, Kevin
Sent: Friday, July 24, 2015 8:58 PM

To: Elman, Barry
Subject: FW: Updated version of 111(b) New/Mod/Recon preamble and Reg Text

From: Hutson, Nick
Sent: Friday, July 24, 2015 8:54 PM
To: Silverman, Steven; Hoffman, Howard; CurryBrown, Amanda; DeFigueiredo, Mark; Marks, Matthew; Marsh, Karen; Johnson, Mary; Fellner, Christian; Boswell, Colin; Jordan, Scott
Cc: Fruh, Steve; Culligan, Kevin; Eck, Janet; Hackel, Angela
Subject: FW: Updated version of 111(b) New/Mod/Recon preamble and Reg Text

All –

These are the files that were just sent to OMB.

Ex 5

Please continue to work in the MASTER copies in SharePoint … if it is available to you.

Nick

Nick Hutson, PhD

Energy Strategies Group

Office of Air & Radiation

U.S. Environmental Protection Agency

Research Triangle Park, NC 27711

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For the reasons stated in the preamble, title 40, chapter I, part 60, 70, 71, and 98 of the Code of the Federal Regulations is amended as follows:

PART 60-- STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, et seq.

2. Part 60 is amended by adding subpart TTTT to read as follows:

Subpart TTTT Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

Sec.

Applicability

Emission Standards

General Compliance Requirements

Monitoring and Compliance Determination Procedures

Notifications, Reports, and Records

Other Requirements and Information

Applicability

§60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU.

§60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced modification or reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (a)(2) of this section.

(1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel), and

(2) Serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (b)(8) of this section.

(1) Your EGU is a steam generating unit or IGCC that is currently and always has been subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of combusting 50 percent or more non-fossil fuel and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than the product of the unit's net design efficiency and the unit's potential electric output or 219,000 MWh, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a

prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit(s) or IGCC that undergoes a modification resulting in an hourly increase in CO2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (e.g., not connected to a natural gas pipeline).

Emission Standards

§60.5515 Which greenhouse gases are regulated by this subpart?

(a) The greenhouse gas regulated by this subpart is carbon dioxide (CO_2).

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of 40 CFR §51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the

pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48) of this chapter.

(2) For the purposes of 40 CFR §52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR §70.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR §70.2 of this chapter.

(4) For the purposes of 40 CFR §71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR §71.2 of this chapter.

§60.5520 What CO_2 emission standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 or Table 2 of this subpart, consistent with paragraphs (b) and (c) of this section, as applicable.

(b) Except as specified in paragraph (c) of the section, you must comply with the applicable gross energy output standard and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "gross energy output."

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the source must comply with the applicable net energy output based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output based standard must petition the Administrator to switch back to complying with the gross energy output based standard.

General Compliance Requirements

§60.5525 What are my general requirements for complying with this subpart?

Compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating month rolling average basis. See Tables 1-2 for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1).

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating month period.

(2) For each affected EGU subject to the CO_2 emissions standard for multi-fuel units, you must determine the total heat input in million Btu's (MMBtu) from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under §60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard (EL) during the compliance period:

Where:

CO_2 emission standard = the emission standard during the compliance period in units of lb/MMbtu.

$HTIP_{ng}$ = the heat input in MMBtu from natural gas during the compliance pe riod.

$HTIP_o$ = the heat input in MMBtu from all fuels other than natural gas that were fired during the compliance period.

120 = allowable emission rate in lbs of CO2/MMBtu for heat input derived from natural gas.

160 = allowable emission rate in lbs of CO2/MMBtu for heat input derived from all fuels other than natural gas.

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (i.e., no more than 30 days after the first 12-operating month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 or Table 2 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in §72.2 of this chapter) on or after the effective date of this rule, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) §63.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) §63.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced commercial operation (as defined in §72.2 of this chapter) prior to the effective date of this rule:

(i) If the date on which emissions reporting is required to begin under §75.64(a) of this chapter has passed prior to the effective date of this rule, emissions reporting shall begin according to §63.5555(c)(3)(i) (for Acid Rain program units), or according to §63.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under §75.64(a) of this chapter occurs on or after the effective date of this rule, then the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under §63.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under §63.5555(c)(3)(iii).

Monitoring and Compliance Determination Procedures

§60.5535 How do I monitor and collect data to demonstrate compliance?

(a) You must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/hr), in accordance with the applicable provisions in §75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see §60.5555(c)).

(b) You must determine the hourly CO_2 mass emissions in kilograms (kg) from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to §75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (e.g., carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with §75.10(a)(3)(iii) of this chapter. If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to §75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from §75.11(b) or submit a petition to the Administrator under §75.66 of this chapter for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in §75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (a)(6)(i) through (iv) of this section. Perform this calculation only for “valid operating hours”, as defined in §60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/hr), obtained either from Equation F-11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section.

(1) You must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr). You may determine site-

specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in §60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) You must use these data to calculate the hourly CO_2 mass emissions.

(d) Consistent with §60.5520, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (d)(2), as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (e.g., lbs of CO2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These

measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. For a combined heat and power (CHP) EGU, as defined in §60.5580, you must also install, calibrate, maintain, and operate meters to continuously (i.e., hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (e.g., lbs of CO2 per MMBtu of heat input), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to Part 75;

(ii) The procedures for monitoring heat input under of 40 CFR 60.107a(d); or

(iii) The procedure for monitoring heat input under 40 CFR 98.33(a)(2) or (a)(3).

(e) Consistent with §60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(f) In accordance with §60.13(g) and §60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard in Table 1 or Table 2 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as "stack operating hours" (as defined in §72.2 of this chapter). If you attain compliance with the applicable emissions standard in §60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(g) In accordance with §60.13(g) and §60.5520 if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the "stack operating time" (as defined in §72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

(h) Heat rate determination and design efficiency for combustion turbines. In accordance with xxxx, you must use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).] Acceptable methods include [but are not limited to] the following testing and analytical methods:

(1) ASME PTC 6-2004 Steam Turbines (incorporated by reference, see §60.17).

(2) ASME PTC 6S Procedures for Routine Performance Test of Steam Turbines (incorporated by reference, see §60.17).

(3) ASME PTC 6.2-2011 Steam Turbines in Combined Cycles (incorporated by reference, see §60.17).

(4) ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17).

(5) ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17).

(6) ISO 2314:2009 Gas turbines – acceptance tests (incorporated by reference, see §60.17).

(7) DIN 1943 Thermal Acceptance of steam turbines (incorporated by reference, see §60.17).

(8) IEC-953-2 Rules for steam turbine thermal acceptance tests. Part 2: Method B - Wide range of accuracy for various types and sizes of turbines (incorporated by reference, see §60.17).

§60.5540 How do I demonstrate compliance with my CO_2 emissions standard?

(a) In accordance with §60.5520, to demonstrate compliance with the applicable CO_2 emission standard in Table 1 or 2 of this subpart, for the initial and each subsequent 12-operating month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through(a)(7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (i.e., either kg/MWh or lb/MMBtu). You must use the hourly CO_2 mass emissions and either the generating load data from §60.5535(d)(1) or the heat input data from §60.5535(d)(2) in the calculations.

(1) Each compliance period shall include only "valid

operating hours" in the compliance period, i.e., operating hours for which:

(i) "Valid data" (as defined in §60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: for hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input based standard applies, for any parameters used to determine the hourly heat input; or

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from §60.5535 for all of the valid operating hours in the compliance period.

(5) Sources subject to output based standards. For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly gross or net energy output (Consistent with §60.5520) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Where: a

$P_{gross/net}$ = In accordance with §60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Calculation of annual basis for standard. Sources complying with energy output-based standards must calculate the basis (i.e., denominator) of their actual annual emission rate in accordance with paragraph (6)(i). Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (6)(ii).

(i) In accordance with §60.5520 if you are subject to an output based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under §60.5535(d)(2).

(7) If you are subject to an output based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures. If you are subject to a heat input based standard, you must calculate the CO2 mass emissions rate for the affected EGU(s) (lb/MMBtu) by dividing the total CO2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the

result to two significant figures.

(b) In accordance with §60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1, Table 2, or the emissions standard calculated in accordance with §60.5525(a)(2) of this subpart.

Notification, Reports, and Records

§60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §60.7(a)(1) and (a)(3) and §60.19, as applicable to your affected EGU(s) (see Table 3 of this Subpart).

(b) You must prepare and submit notifications specified in §75.61 of this chapter, as applicable to your affected EGUs.

§60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by §60.5525 to conduct initial and on-going compliance determinations on a 12-operating month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the

first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in §60.5540. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-

operating month compliance period described in paragraph (a)(1)(i) of this section (i.e., the total number of valid operating hours (as defined in §60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with §60.5520, the CO_2 emissions standard (as identified in Table 1 or 2) with which your affected EGU must comply; and

(vi) Consistent with §60.5520, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with §60.5520, gross energy output or net energy output sold to an electric grid over the 4 quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c) (1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3) (i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with §75.64(a), i.e., beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in §75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in §72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under §75.64(a), if that date occurs on or after the effective date of this rule; or

(B) The effective date of this rule, if the date on which reporting would ordinarily be required to begin under §75.64(a) has passed prior to the effective date of this rule.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with §75.4(j) of this chapter, §75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in §60.5540(a)(1)), and shall not be used in the compliance determinations under §60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under §72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under §72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under §72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optional) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR Part 98 Subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR Part 98 subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR Part 98 subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g)

of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR Part 98 subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision, and provide public notice of any proposed action on a petition before the Administrator takes final action.

§60.5560 What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in §60.7 (b) and (f).

(b) (1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under §75.53(g) and (h) of this chapter;

(ii) Operating parameter records under §75.57(b)(1) through (b)(4) of this chapter;

(iii) The records under §75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under §75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under §75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under §75.58(c)(1), paragraphs (c)(1)(i), (c)(1)(ii), and (c)(1)(viii) through (c)(1)(xiv), for oil flow meters;

(vii) The records under §75.58(c)(4), paragraphs (c)(4)(i), (c)(4)(ii), (c)(4)(iv), (c)(4)(v), and (c)(4)(vii) through (c)(4)(xi), for gas flow meters;

(viii) The quality-assurance records under §75.59(a) of this chapter, paragraphs (a)(1) through (a)(12) and (a)(15), for CEMS;

(ix) The quality-assurance records under §75.59(a) of this chapter, paragraphs (b)(1) through (b)(4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under §75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs);

(2) Each compliance period, including, each 12-operating month compliance period.

(d) Consistent with §60.5520, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU’s gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

§60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 3 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§60.5570 What parts of the General Provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the General Provisions in §60.1 through 60.19, listed in Table 3 to this subpart, do not apply to your affected EGU.

§60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under §60.8(b).

§60.5580 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating._

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as "cogeneration") means an electric generating unit that that use a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (e.g., electric plus thermal output) on a lower heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17); diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17); kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17); biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17); or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see

§60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (i.e., meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the

total gross energy output consists of useful thermal output on a 12-operaitng month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means a EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle unit or *IGCC* means a combined cycle stationary combustion turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

ISO conditions means 288 Kelvin (15° C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at

ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric sales means

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output

on an annual basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host EGU or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that that result from a grid emergency are not included when calculating net-electric sales.

Net-electric output means: the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net energy output means:

(i) Except as provided under paragraph (ii) of this definition, the net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(ii) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output;

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25° C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Potential electric output means 33 percent or the design efficiency, whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

Useful thermal output means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected facility to operate to avert loss of load.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in §75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 or Table 2 of this subpart.

Table 1 of Subpart TTTT of Part 60 – CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities that Commenced Construction after January 8, 2014 and Reconstruction or Modification after June 18, 2014 (net energy output-based standards are only applicable to affected units subject to a federally enforceable permit condition limiting GHG emissions on a net energy output basis)

Note: numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures

Affected EGU	**CO_2 Emission Standard**
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC)	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh)
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less	910 kg of CO_2 per MWh of gross energy output (2,000 lb CO_2/MWh)
Reconstructed steam generating unit or IGCC EGU that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h)	820 kg of CO_2 per MWh of gross energy output (1,800 lb CO_2/MWh)
Modified steam generating or IGCC unit	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: 1. 1,800 lb CO_2/MWh-gross for units with a base load rating greater than 2,000 MMBtu/h.; or 2. 2,000 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or less.

Table 2 of Subpart TTTT of Part 60 – CO_2 Emission Standards for Affected Stationary Combustion Turbines that Commenced Construction after January 8, 2014 and Reconstruction after June 18, 2014 (net energy output-based standards are only applicable to affected units subject to a federally enforceable permit condition limiting GHG emissions on a net energy output basis)

Note: numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures

Affected EGU	CO_2 Emission Standard[1]
Newly constructed or reconstructed stationary combustion turbine that supplies more than the design efficiency times the potential electric output as net-electric sales on a 3 year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating month rolling average basis.	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh)
Newly constructed or reconstructed stationary combustion turbine that supplies one-third or the design efficiency, whichever is greater, of its potential electric output or less as net-electric sales on a 3 year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating month rolling average basis.	50 kg CO2 per gigajoule (GJ) of heat input (120 lb CO2/MMBtu)
Stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating month rolling average basis.	69 kg CO2/GJ of heat input (160 lb/MMBtu)

[1] See procedures for establishing and revising the compliance option under § 60.5520.

Table 3 to Subpart TTTT of Part 60 – Applicability of Subpart A General Provisions to Subpart TTTT

General Provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5580
§60.3	Units and Abbreviations	Yes	
§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in 60.7(a)(1) and (a)(3) and to keep records of malfunctions in §60.7(b), if applicable
§60.8	Performance tests	No	
§60.9	Availability of Information	Yes	
§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	All monitoring is done according to Part 75
§60.14	Modification	No	
§60.15	Reconstruction	No	

§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.

PART 70— STATE OPERATING PERMIT PROGRAMS

3. The authority citation for part 70 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

4. Section 70.2 is amended by revising the introductory text, removing "or" from the end of paragraph (2), adding "or" to the end of paragraph (3), and adding paragraph (4) to the definition of "Regulated pollutant (for presumptive fee calculation)."

The revision and additions read as follows:

§70.2 Definitions.

* * * * *

Regulated pollutant (for presumptive fee calculation), which

is used only for purposes of §70.9(b)(2), means any regulated

air pollutant except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

5. Section 70.9 is amended by revising paragraph (b)(2)(i), and by adding paragraph (b)(2)(v) to read as follows:

§70.9 Fee determination and certification.

* * * * *

(b) * * *

(2)(i) The Administrator will presume that the fee schedule meets the requirements of paragraph (b)(1) of this section if it would result in the collection and retention of an amount not less than $25 per year [as adjusted pursuant to the criteria set forth in paragraph (b)(2)(iv) of this section] times the total tons of the actual emissions of each regulated pollutant (for presumptive fee calculation) emitted from part 70 sources and any GHG cost adjustment required under paragraph (b)(2)(v) of this section.

* * * * *

(v) *GHG cost adjustment*. The amount calculated in paragraph (b)(2)(i) of this section shall be increased by the GHG cost adjustment determined as follows: For each activity identified in the following table, multiply the number of activities performed by the permitting authority by the burden hours per activity, and then calculate a total number of burden hours for all activities. Next, multiply the burden hours by the average cost of staff time, including wages, employee benefits and overhead.

Activity	Burden hours per activity
GHG completeness determination (for initial	

permit or updated application)	43
GHG evaluation for a permit modification or related permit action	7
GHG evaluation at permit renewal	10

*   *   *   *   *

PART 71— FEDERAL OPERATING PERMIT PROGRAMS

6. The authority citation for part 71 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

7. Section 71.2 is amended by removing "or" from the end of paragraph (2), adding "or" to the end of paragraph (3), and adding paragraph (4) to the definition of "Regulated pollutant (for fee calculation)."

The revisions and additions read as follows:

§71.2 Definitions.

*   *   *   *   *

Regulated pollutant (for fee calculation), which is used only for purposes of §71.9(c), means any "*regulated air pollutant*" except the following:

*   *   *   *   *

(4) Greenhouse gases.

*   *   *   *   *

8. Section 71.9 is amended by:

a. Revising paragraphs (c)(1), (c)(2)(i), (c)(3), and (c)(4), and

b. Adding paragraph (c)(8).

The revisions and additions read as follows:

§71.9 Permit fees.

*   *   *   *   *

(c) * * *

(1) For part 71 programs that are administered by EPA, each part 71 source shall pay an annual fee which is the sum of:

(i) $32 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(ii) Any GHG fee adjustment required under paragraph (c)(8) of this section.

(2) * * *

(i) Where the EPA has not suspended its part 71 fee collection pursuant to paragraph (c)(2)(ii) of this section, the annual fee for each part 71 source shall be the sum of:

(A) $24 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(B) Any GHG fee adjustment required under paragraph (c)(8) of this section.

* * * * *

(3) For part 71 programs that are administered by EPA with contractor assistance, the per ton fee shall vary depending on the extent of contractor involvement and the cost to EPA of contractor assistance. The EPA shall establish a per ton fee that is based on the contractor costs for the specific part 71 program that is being administered, using the following formula:

Cost per ton=(E ×32)+[(1− E)×$ C]

Where E represents EPA's proportion of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, 1- E represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed by using the following formula:

C =[B + T + N] divided by 12,300,000

Where B represents the base cost (contractor costs), where T represents travel costs, and where N represents nonpersonnel data management and tracking costs. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

(4) For programs that are delegated in part, the fee shall be computed using the following formula:

Cost per ton=(E ×32)+(D ×24)+[(1− E − D)×$ C]

Where E and D represent, respectively, the EPA and delegate agency proportions of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, 1− E − D

represents the contractor's effort, and *C* represents the contractor assistance cost on a per ton basis. *C* shall be computed using the formula for contractor assistance cost found in paragraph (c)(3) of this section and shall be zero if contractor assistance is not utilized. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

* * * * *

(8) *GHG fee adjustment*. The annual fee shall be increased by a GHG fee adjustment for any source that has initiated an activity listed in the following table since the fee was last paid. The GHG fee adjustment shall be equal to the set fee provided in the table for each activity that has been initiated since the fee was last paid:

Activity	Set fee
GHG completeness determination (for initial permit or updated application)	$2,236
GHG evaluation for a permit modification or related permit action	$364
GHG evaluation at permit renewal	$520

* * * * *

PART 98— MANDATORY GREENHOUSE GAS REPORTING

9. The authority citation for part 98 is revised to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart PP—Suppliers of Carbon Dioxide

10. Section 98.426 is amended by adding paragraph (h) to read as follows:

§98.426 Data reporting requirements.

* * * * *

(h) If you capture a CO_2 stream from an electricity generating unit that is subject to subpart D of this part and transfer CO2 to any facilities that are subject to subpart RR of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the subpart D facility,

(2) Report each facility identification number associated with the annual GHG reports for each subpart RR facility to which CO2 is transferred, and

(3) Report the annual quantity of CO2 in metric tons that is transferred to each subpart RR facility.

11. Section 98.427 is amended by adding paragraph (d) to read as follows:

§98.427 Records that must be retained.

* * * * *

(d) Facilities subject to §98.426(h) must retain records of CO_2 in metric tons that is transferred to each subpart RR facility.

To: Stenhouse, Jeb[Stenhouse.Jeb@epa.gov]; Victor, Meg[Victor.Meg@epa.gov]; Conlin, Beth[Conlin.Beth@epa.gov]; Marten, Alex[Marten.Alex@epa.gov]
From: Evans, DavidA
Sent: Wed 7/29/2015 3:00:24 AM
Subject: Version of FP preamble...
Working Version CPP FP Preamble Draft_072715_download150728 11pm w jeb and dae exchange.docx

…with my responses to Jeb's text boxes.

Ex 5

I suspect Alex and Beth may want to review what Jeb has as written on the sharepoint site. Ex 5

Ex 5

Ex 5

d

To: Curry, Bridgid[Curry.Bridgid@epa.gov]; Marten, Alex[Marten.Alex@epa.gov]; Owens, Nicole[Owens.Nicole@epa.gov]; Evans, DavidA[Evans.DavidA@epa.gov]
Cc: Elman, Barry[Elman.Barry@epa.gov]; Nickerson, William[Nickerson.William@epa.gov]; Beauvais, Joel[Beauvais.Joel@epa.gov]
From: Rennert, Kevin
Sent: Wed 7/29/2015 1:56:09 PM
Subject: RE: FP RIA - sending first review draft tonight
EO12866_CPP_Federal_Plan_2060_AS47_RIA Final_20150728.docx

+ Bill, as we just touched base about this.

Ex 5

From: Curry, Bridgid
Sent: Wednesday, July 29, 2015 9:55 AM
To: Rennert, Kevin; Marten, Alex; Owens, Nicole; Evans, DavidA
Cc: Elman, Barry
Subject: RE: FP RIA - sending first review draft tonight

We will work with OMB to get the RIA uploaded in ROCIS today. **Ex 5** **Ex 5** This rule is not economically significant so we don't have to worry about submitting the economic data table.

Thanks,

Bridgid

From: Rennert, Kevin
Sent: Wednesday, July 29, 2015 9:30 AM
To: Marten, Alex; Owens, Nicole; Evans, DavidA
Cc: Elman, Barry; Curry, Bridgid
Subject: RE: FP RIA - sending first review draft tonight

Thanks. Nicole is out right now, so I'll look into what else, if anything, needs to be done procedurally. Thanks, Alex. -Kevin

From: Marten, Alex
Sent: Wednesday, July 29, 2015 9:29 AM
To: Owens, Nicole; Evans, DavidA
Cc: Elman, Barry; Curry, Bridgid; Rennert, Kevin
Subject: RE: FP RIA - sending first review draft tonight

Ex 5

I am happy to help in any way I can.

--

Alex L. Marten
phone: (202) 566-2301
email: marten.alex@epa.gov

From: Owens, Nicole
Sent: Wednesday, July 29, 2015 9:18 AM
To: Evans, DavidA
Cc: Elman, Barry; Marten, Alex; Curry, Bridgid
Subject: Re: FP RIA - sending first review draft tonight

Hi.

I was out yesterday afternoon. Did this get taken care of? I am at home working today for the morning, so you can call me at **Personal cell/email**

Nicole

From: Evans, DavidA
Sent: Tuesday, July 28, 2015 6:16 PM
To: Owens, Nicole
Cc: Elman, Barry; Marten, Alex; Curry, Bridgid
Subject: FW: FP RIA - sending first review draft tonight

Hi Nicole,

Ex 5

I'm at my desk if you want to give me a ring. 566 2358

Dave

From: Evans, DavidA
Sent: Tuesday, July 28, 2015 5:38 PM
To: Beauvais, Joel; Rennert, Kevin
Cc: McGartland, Al; Barry Elman; Marten, Alex
Subject: FP RIA - sending first review draft tonight

Hi Joel, and Kevin

Ex 5

Details follow:

Ex 5

Ex 5

Ex 5

In other news, an updated version of the EG RIA was sent today.

Am now turning to the FP preamble, Ex 5

Ex 5

Let us know if you have any questions.

Dave

To: Beauvais, Joel[Beauvais.Joel@epa.gov]
Cc: Rennert, Kevin[Rennert.Kevin@epa.gov]; Evans, DavidA[Evans.DavidA@epa.gov]; Marten, Alex[Marten.Alex@epa.gov]; Rees, Sarah[Rees.Sarah@epa.gov]
From: Elman, Barry
Sent: Wed 7/29/2015 2:18:22 AM
Subject: FW: Revised versions of 111(b) preamble/rule
111b preamble_DRAFT_072815_clean.docx
SummaryofInteragencyCommentsUnderEO 12866_13563_111(b) New-Mods 2060-AQ91 Final_7 26 2015_EPAResponse.docx
111b preamble_DRAFT_0782815_RLSO_compare to 072415.docx

Joel,

Here's the latest passback to OMB on the 111(b) rule. This includes the latest version of the preamble and reg text, as well as responses to several comments. There also continues to be an email exchange with OMB on interagency comments. We received the latest round of interagency comments on the FP earlier this evening. Ex 5

Ex 5

Barry

From: Hutson, Nick
Sent: Tuesday, July 28, 2015 6:21 PM
To: Silverman, Steven; Marks, Matthew; Johnson, Mary; Fellner, Christian; CurryBrown, Amanda; DeFigueiredo, Mark; Herring, Jeff; Hackel, Angela; Svendsgaard, Dave; Hoffman, Howard; Jordan, Scott; Marsh, Karen; Elman, Barry
Cc: Fruh, Steve; Vasu, Amy
Subject: FW: Revised versions of 111(b) preamble/rule

All … FYI … these files and the message below were submitted to OMB this evening.

1. A clean version of the latest version of the 111(b) preamble and rule for GHG emissions from new, modified, and reconstructed EGUs – this version incorporates changes responsive to Interagency comments/suggestions and also changes that we have made as we continue to

improve the document. The document also has EPA responses to OMB/Interagency comments in marginal comment balloons.

2. A RLSO version showing changes that have been made – compared to the clean version that was submitted to OMB on 07/24/15.

3. EPA's response to summary of comments from review of the 07/24/15 submission.

We are continuing to work on the document. However, we expect no more substantive changes to the document.

Specifically we are still working on:

1. We are reading through to ensure consistency in terminology, formatting, punctuation, grammar, etc.

2. We are revising some sections (esp. turbine sections) for readability and clarity – however, again, no substantive or directional changes.

3. We are working on the NTTA section and amendments to 60.17 – this involves making sure we are properly incorporating the test methods (e.g., ASME test methods for determining efficiency and ANSI method for assuring consistent accuracy of electricity monitoring)

4. We are reviewing regulatory text to make sure it is as easy as possible for the public to understand & verifying that it is consistent with the preamble.

Thanks,

Nick

Nick Hutson, PhD

Energy Strategies Group

Office of Air & Radiation

U.S. Environmental Protection Agency

Research Triangle Park, NC 27711

tel: +1 919 541 2968

email: hutson.nick@epa.gov

To: Rennert, Kevin[Rennert.Kevin@epa.gov]
Cc: Marten, Alex[Marten.Alex@epa.gov]; Elman, Barry[Elman.Barry@epa.gov]
From: Evans, DavidA
Sent: Tue 7/28/2015 6:32:58 PM
Subject: RLSO of FP preamble
EO12866_CPP Federal Plan 2060 AS47 NPRM_20150727 RLSO.docx

Kevin,

Ex 5 As I understand it, this is the RLSO that goes along with the clean version of the preamble that Alex Marten sent.

d

From: Victor, Meg
Sent: Monday, July 27, 2015 12:48 PM
To: Evans, DavidA
Subject: FW: Urgent: Mgmt. Review Requested - CPP Federal Plan for OMB
Importance: High

Meg Victor

Clean Air Markets Division

(202) 343-9193

From: Jones, Toni
Sent: Monday, July 27, 2015 11:53 AM
To: Culligan, Kevin; Adamantiades, Mikhail
Cc: Stenhouse, Jeb; Hackel, Angela; Boswell, Colin; Swanson, Nicholas; Victor, Meg; Conlin,

Beth; Schramm, Daniel; Ortega, Kellie
Subject: Urgent: Mgmt. Review Requested - CPP Federal Plan for OMB
Importance: High

Good morning,

Attached, please find the revised CPP Federal Plan preamble and the response to OMB comments document for your review.

The attached file named "EO 12866…RLSO.dox " shows edits, in tracked changes, made to the package since the initial submittal to OMB. Ex 5 Ex 5

Ex 5

Ex 5

Kind regards,

Toni

Toni Wyche Jones, EI, CFM | Fuels & Incineration Group | Sector Policies & Programs Division - Mail Code E143-05 | Office of Air Quality Planning & Standards | U.S. Environmental Protection Agency | RTP, NC 27711 | Phone: (919) 541-0316 |

To: Deck, Leland[Deck.Leland@epa.gov]; Shouse, Kate[Shouse.Kate@epa.gov]; Risley, David[Risley.David@epa.gov]; Hutson, Nick[Hutson.Nick@epa.gov]; Evans, DavidA[Evans.DavidA@epa.gov]; Marten, Alex[Marten.Alex@epa.gov]; Fellner, Christian[Fellner.Christian@epa.gov]; Johnson, Mary[Johnson.Mary@epa.gov]; Culligan, Kevin[Culligan.Kevin@epa.gov]; Hubbell, Bryan[Hubbell.Bryan@epa.gov]; Silverman, Steven[silverman.steven@epa.gov]
Cc: Weatherhead, Darryl[Weatherhead.Darryl@epa.gov]; Stenhouse, Jeb[Stenhouse.Jeb@epa.gov]; Macpherson, Alex[Macpherson.Alex@epa.gov]
From: CurryBrown, Amanda
Sent: Tue 7/28/2015 2:08:45 AM
Subject: FW: Updated Version of 111(b) RIA and Response to Interagency Comments
EO 12866_111(b) New-Mods 2060-AQ91 RIA Final_07272015.docx
EO 12866_111(b) New-Mods 2060-AQ91 RIA Final_07272015_CLEAN.docx
SummaryofinteragencycommentsunderEO 12866_111(b) New-Mods 2060-AQ91 RIA Final_7_21_2015.docx

Hi All,

See attached for the version of the RIA that went to OMB this evening. (Hooray!) I will post the working version to the sharepoint site when I get to the office in the morning. Ex 5
Ex 5

Thanks again for all your help… definitely getting close now!

Amanda

From: CurryBrown, Amanda
Sent: Monday, July 27, 2015 9:51 PM
To: 'Nathan_J._Frey@omb.eop.gov'
Cc: 'Aaron_L_Szabo@omb.eop.gov'; Nick Hutson (Hutson.Nick@epa.gov); Fruh, Steve; Culligan, Kevin; Weatherhead, Darryl
Subject: Updated Version of 111(b) RIA and Response to Interagency Comments

Hi Nathan,

Please see attached for a revised version of the 111b RIA and response to the most recent set of

OMB comments. I've included a clean version, as well as a RLSO that shows changes since the last submission on 7/14.

Please let me know if you have any questions.

Thanks!

Amanda

Amanda Curry Brown

Health and Environmental Impacts Division

U.S. EPA Office of Air Quality Planning and Standards

919.541.3808

CurryBrown.Amanda@epa.gov

United States Environmental Protection Agency

Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

EPA-452/R-15-005
August 2015

Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impacts Division
Research Triangle Park, NC

CONTACT INFORMATION

This document has been prepared by staff from the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Questions related to this document should be addressed to Amanda Curry Brown, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711 (email: CurryBrown.Amanda@epa.gov).

ACKNOWLEDGEMENTS

In addition to EPA staff from the Office of Air Quality Planning and Standards, personnel from the U.S. EPA Office of Atmospheric Programs and Office of Policy contributed data and analysis to this document.

ACRONYMS

AEO	Annual Energy Outlook
ANSI	American National Standards Institute
ASTM	American Society for Testing and Materials
BPT	Benefit-per-Ton
BSER	Best System of Emissions Reduction
Btu	British Thermal Units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CESA	Clean Energy States Alliance
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CRA	Congressional Review Act
CRF	Capital Recovery Factor
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbines
CUA	Climate Uncertainty Adder
DOE	U.S. Department of Energy
EGU	Electric Generating Unit
EIA	U.S. Energy Information Administration
ELG	Effluent Limitation Guidelines
EMM	Electricity Market Module
EO	Executive Order
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operating and Maintenance
FR	Federal Register
FRCC	Florida Reliability Coordinating Council
GDP	Gross Domestic Product
GHG	Greenhouse Gas

GS	Geologic Sequestration
GW	Gigawatt
GWh	Gigawatt-hours
IAM	Integrated Assessment Model
ICR	Information Collection Request
IGCC	Integrated Gasification Combined Cycle
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
IPM	Integrated Planning Model
IPP	Independent Power Producers
IRP	Integrated Resource Plan
IWG	Interagency Working Group
kWh	Kilowatt-hour
lb	Pound or Pounds
LCOE	Levelized Cost of Electricity
MATS	Mercury and Air Toxics Standards
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NATCARB	National Carbon Sequestration Database and Geographic Information System
NCA3	Third National Climate Assessment
NEEDS	National Electric Energy Data System
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NOAK	Nth of a Kind
NODA	Notice of Data Availability
NO_X	Nitrogen Oxide
NRC	National Research Council
NSPS	New Source Performance Standard
NTTAA	National Technology Transfer and Advancement Act
OMB	Office of Management and Budget
$PM_{2.5}$	Fine Particulate Matter

PM NAAQS	National Ambient Air Quality Standards for Particulate Matter
PRA	Paperwork Reduction Act
RES	Renewable Electricity Standards
RFA	Regulatory Flexibility Act
RGGI	Regional Greenhouse Gas Initiative
RIA	Regulatory Impact Analysis
RPS	Renewable Portfolio Standards
SC-CO_2	Social Cost of Carbon
SCPC	Super Critical Pulverized Coal
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Tcf	Trillion Cubic Feet
TkWh	Trillion Kilowatt-Hours
TSD	Technical Support Document
TS&M	Transportation Storage and Monitoring
UMRA	Unfunded Mandates Reform Act
U.S.C.	U.S. Code
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
VOM	Variable Operating and Maintenance

Contents

EXECUTIVE SUMMARY

This Regulatory Impact Analysis (RIA) discusses potential benefits, costs, and economic impacts of the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (herein referred to as the EGU New, Modified, and Reconstructed Source GHG Standards).

ES.1 Background and Context of Final Rule

The final EGU New, Modified and Reconstructed Source GHG Standards will set emission limits for greenhouse gas emissions (GHG) from newly constructed, modified, and reconstructed fossil fuel-fired electricity generating units (EGUs). These limits will apply to carbon dioxide (CO_2) emissions from any affected fossil fuel-fired EGU. The United States Environmental Protection Agency (EPA) is finalizing requirements for these sources because CO_2 is an air pollutant under the Clean Air Act, section 111 (a) and (b) of the Act authorize the EPA to establish standards of performance for air pollutants emitted from source categories like the one here listed by the EPA because the source category causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Fossil fuel-fired power plants are the country's largest stationary source emitters of GHGs. As stated in the EPA's Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act (CAA) (74 FR 66518), and summarized in Chapter 3 of this RIA, the anthropogenic buildup of GHGs in the atmosphere is the cause of most of the observed global warming over the last 50 years.

On June 25, 2013, in conjunction with the announcement of his Climate Action Plan, President Obama issued a Presidential Memorandum directing the EPA to issue a proposal to address carbon pollution from new power plants by September 30, 2013, and to issue "standards, regulations, or guidelines, as appropriate, which address carbon pollution from modified, reconstructed, and existing power plants." On September 20, 2013, pursuant to authority in CAA section 111(b), EPA Administrator Gina McCarthy signed proposed carbon pollution standards for newly constructed fossil fuel-fired power plants (79 FR 1430, January 8, 2014).

The EPA subsequently issued a Notice of Data Availability (NODA), soliciting comment on its initial interpretation of provisions in the Energy Policy Act of 2005 and the Internal Revenue

Code, and also soliciting comment on a Technical Support Document, which addressed these provisions' relationship to the factual record supporting the proposed rule (79 FR 10750, February 26, 2014).

On June 2, 2014, Administrator McCarthy signed proposed standards of performance, also pursuant to CAA section 111(b), to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and stationary combustion turbines (79 FR 34959, June 18, 2014).

In this action, the EPA is finalizing standards of performance to limit emissions of CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Consistent with the requirements of CAA section 111(a) and (b), these standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the EPA has determined has been adequately demonstrated for each type of unit.

ES.2 Summary of the Final Rule

The EPA has determined that the BSER for newly constructed steam generating units is a supercritical pulverized coal (SCPC) unit using post-combustion partial carbon capture and storage (CCS) technology to meet an emission limitation of 1,400 lb CO_2/MWh-gross. The standard for steam generating units that conduct modifications resulting in a potential hourly increase in CO_2 emissions (mass per hour) of more than 10 percent[1] is a unit-specific emission limitation consistent with each modified unit's best one-year historical performance during the years from 2002 to the time of the modification. For reconstructed steam generating units, the BSER is the most efficient demonstrated generating technology for these types of units (i.e., meeting a standard of performance consistent with a reconstructed boiler using most efficient steam conditions available, even if the boiler was not originally designed to do so).

The BSER for primarily natural gas-fired stationary combustion turbines expected to serve intermediate and base load power demand is the use of well-designed, well-maintained, and well-operated natural gas combined cycle (NGCC) technology. These units will be required to meet an emission standard of 1,000 lb CO_2/MWh-gross output (or 1,030 lb CO2/MWh of net energy output). For peaking and multi-fuel-fired units, BSER is the use of clean fuels.

The BSER determination and final standards for each affected EGU are shown in Table ES-

[1] More than 10 percent as compared to its highest potential during the previous five years. The EPA is not finalizing standards for units that conduct modifications with a potential hourly increase in CO_2 of 10 percent of less.

1. The applicability of these standards based on the capacity and operation of a source are described in the preamble for this final rule. The final standards for all source categories will be met on a 12-operating month rolling average basis.

ES.3 Key Findings of Economic Analysis

CAA Section 111(b) requires that the new source performance standards (NSPS) be reviewed every eight years. As a result, this rulemaking's analysis is primarily focused on projected impacts within the current eight-year NSPS timeframe.[2] As explained in detail in this document, energy market data and projections support the conclusion that, even in the absence of this rule, expected economic conditions will lead electricity generators to choose new generation technologies that meet the standards without the need for additional controls.

The base case modeling the EPA performed for this rule and for other recent air rules projects that, even in the absence of this action, new fossil-fuel fired capacity constructed through 2022 and the years following will most likely be NGCC capacity that complies with the final standards. Analyses performed both by the EPA and the Energy Information Administration (EIA) project that new compliant natural gas-fired units and renewable sources are likely to be the technologies of choice for new generating capacity due to current and projected economic market conditions.[3]

[2] In some cases, conditions in the analysis year of 2022 (eight years from proposal) are represented by results of power sector modeling for the year 2020. An analysis year of 2023 (eight years from finalization) would not substantively alter the overall conclusions of this RIA.

[3] See the EIA's 2009 to 2015 Annual Energy Outlooks (AEO).

Table ES-1. Summary of BSER and Final Standards for Affected EGUs

Affected EGU	BSER	Standard
Newly Constructed Fossil Fuel-Fired Steam Generating Units	Efficient new SCPC utility boiler implementing partial CCS	1,400 lb CO_2/MWh-gross
Modified Fossil Fuel-Fired Steam Generating Units	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades	Sources making modifications resulting in an increase in CO_2 hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,800 lb CO_2/MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.
Reconstructed Fossil Fuel-Fired Steam Generating Units	Most efficient generating technology at the affected EGU.	1. 1,800 lb CO_2/MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.
Newly Constructed and Reconstructed Natural Gas-Fired Stationary Combustion Turbines	Efficient NGCC technology for natural gas-fired base load units and clean fuels for non-base load and multi-fuel-fired units.	1. 1,000 lb CO_2/MWh-gross or 1,030 lb CO_2/MWh-net for base load natural gas-fired units. 2. 120 lb CO_2/MMBtu for non-base load natural gas-fired units. 3. 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units.

Historically, the EPA has been notified of very few modifications (for criteria pollutants) or reconstructions under the NSPS provisions. As such, the EPA anticipates few covered units will trigger the reconstruction or modification provisions in the period of analysis.

Therefore, based on the analysis presented in Chapter 4 of this RIA, the EPA anticipates that the EGU New, Modified, and Reconstructed Source GHG Standards will result in negligible CO_2 emission changes, energy impacts, quantified benefits, costs, and economic impacts by

2022. Accordingly, the EPA also does not anticipate this rule will have any significant impacts on the price of electricity, employment or labor markets, or the U.S. economy.

Although the primary conclusion of the analysis presented in this RIA is that the standards for newly constructed EGUs will result in negligible costs and benefits, the EPA has also performed several illustrative analyses, in Chapter 5, that show the potential impacts of the rule if certain key assumptions were to change. This analysis finds that under conditions that deviate from current projections about natural gas prices, the monetized benefits of the standards to society likely outweigh the costs of the standards. The analysis also presents the costs and benefits that would occur in the unlikely case where assumptions about economic conditions do not change but an operator chooses to construct new coal-fired capacity. In that analysis, monetized benefits outweigh costs under a range of assumptions.

The final standards provide the benefit of regulatory certainty that any new coal-fired power plant must limit CO_2 emissions to the level of the standard of performance: 1,400 lb CO_2/MWh. The final standards also reduce regulatory uncertainty by defining the requirements to limit emissions of CO_2 from new, modified, and reconstructed fossil fuel-fired steam generating sources.

In addition, the EPA intends this rule to send a clear signal about the current and future status of CCS technology. Additional CCS applications are expected to lead to improvements in this technology's performance and consequent reductions in its cost. Identifying post-combustion partial CCS technology as the BSER for coal-fired power plants promotes further development and encourages continued research of CCS,[4,5] which is important for long-term CO_2 emission reductions.

The final standards also provide regulatory certainty for stationary combustion turbines that, along with new renewable sources, are expected to be the primary technology options to provide new generating capacity in the analysis period. Any new stationary combustion turbines must be well-designed, well-maintained, and well-operated.

[4] Statement by Department of Energy Secretary Steven Chu. Statement by Secretary Chu. http://energy.gov/articles/building-clean-energy-partnerships-china-and-japan.

[5] Friedman, Dr. Julio S. "A U.S. – China CCS Roadmap." Lawrence Livermore National Laboratory Carbon Management Program. http://www.nrcce.wvu.edu/cleanenergy/docs/Friedmann.pdf.

CHAPTER 1
INTRODUCTION AND BACKGROUND

1.1 Introduction

In this action, the U.S. Environmental Protection Agency (EPA) is adopting emission limits for greenhouse gases (GHGs), specifically carbon dioxide (CO_2), emitted from fossil fuel-fired EGUs. This document presents the expected economic impacts of the Electricity Generating Unit (EGU) New, Modified, and Reconstructed Source GHG Standards rule through 2022, including some projections for years up to 2030. Based on the analysis presented in Chapter 4, the current forecast of economic conditions (e.g., price of natural gas) will lead electricity generators to choose fuels and technologies that will meet the final standards for new sources without the need for additional control, even in the absence of the rule. As a result, the final new source standards are expected to have no, or negligible, costs or quantified benefits associated with them. However, should forecast economic conditions change or operators choose to construct new coal-fired capacity, we project that emission reductions associated with the standard may result in monetized benefits exceeding the cost of control, and would also provide unquantified benefits. (See Chapter 5.) The EPA has reached a similar conclusion for the final reconstruction and modification provisions. Based on historical information that has been reported to the EPA, we anticipate few covered units will trigger the reconstruction or modification provisions in the period of analysis. As a result, we anticipate negligible costs or benefits associated with those standards. This chapter contains background information on the rule and an outline of the chapters of the report.

1.1.1 Legal Basis for this Rulemaking

Section 111 of the Clean Air Act (CAA) requires performance standards for air pollutant emissions from categories of stationary sources which are listed by the EPA because they may reasonably contribute to the endangerment of public health or welfare. In April 2007, the Supreme Court ruled in *State of Massachusetts v. EPA* that GHGs meet the definition of an "air pollutant" under the CAA. This ruling clarified that the authorities and requirements of the CAA apply to GHGs. As a result, the EPA is authorized to make decisions about whether to regulate GHGs under certain provisions of the CAA, based on relevant statutory criteria. Because CO_2 is an air pollutant emitted from a source category the EPA has listed for purposes of section 111, the EPA may establish standards under section 111 (a) and (b) for CO_2 for this source category. In 2009, the EPA issued a final determination that emissions of certain specified GHGs endanger both the public health and the public welfare of current and future generations in the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the CAA (74 FR 66,496; Dec. 15, 2009), and has explained in detail how emissions of CO_2 from this source category cause or contribute significantly to air pollution that endangers health and welfare. As described in Chapter 2, this source category contributes more CO_2 than any other domestic stationary source.

On June 25, 2013, in conjunction with the announcement of his Climate Action Plan, President Obama issued a Presidential Memorandum directing the EPA to issue a proposal to address carbon pollution from new power plants by September 30, 2013, and to issue "standards, regulations, or guidelines, as appropriate, which address carbon pollution from modified, reconstructed, and existing power plants." On September 20, 2013, pursuant to authority in CAA section 111(b), EPA Administrator Gina McCarthy signed proposed carbon pollution standards for newly constructed fossil fuel-fired power plants (79 FR 1430, January 8, 2014).

The EPA subsequently issued a Notice of Data Availability (NODA), soliciting comment on its initial interpretation of provisions in the Energy Policy Act of 2005 and the Internal Revenue Code, and also soliciting comment on a Technical Support Document, which addressed these provisions' relationship to the factual record supporting the proposed rule (79 FR 10750, February 26, 2014).

On June 2, 2014, Administrator McCarthy signed proposed standards of performance, also pursuant to CAA section 111(b), to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and stationary combustion turbines (79 FR 34959, June 18, 2014).

In this action, the EPA is finalizing standards of performance to limit emissions of CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Consistent with the requirements of CAA section 111(b), these standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the EPA has determined has been adequately demonstrated for each type of unit.

1.1.2 Regulatory Analysis

In accordance with Executive Order (EO) 12866, EO 13563, and the EPA's Guidelines for Preparing Economic Analyses, the EPA prepared this Regulatory Impact Analysis (RIA) for this "significant regulatory action." This rule is not anticipated to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities and is therefore not an "economically significant rule." However, under EO 12866 (58 FR 51,735, October 4, 1993), this action is a "significant regulatory action" because it "raises novel legal or policy issues arising out of legal mandates." As a matter of policy, the EPA has attempted to provide a thorough analysis of the potential impacts of this rule, consistent with requirements of the Executive Orders.

This RIA addresses the potential costs and benefits of the new, modified, and reconstructed source emission limits that are the focus of this action. As described in Chapter 4, the EPA does not anticipate any costs or quantified benefits will result from the new source standards if utilities and project developers make the type of choices related to new generation sources that are forecast by the EPA's and EIA's models and that many publicly available utility integrated resource plans (IRPs) indicate are likely. However, if future economic conditions (e.g., natural gas prices) differ from these forecasts and utilities would have constructed new coal-fired units in the baseline, there could be some compliance costs. In these cases, the EPA's analysis shows that the rule will result in net benefits to society under a range of assumptions.

For new sources the EPA and EIA, through their models[6], project that new fossil-fired electric utility steam generating units and natural gas-fired stationary combustion turbines that meet the applicability criteria would meet the respective standards under this rule in the baseline where no such standards are implemented. Some limited new coal-fired units with federally-supported carbon capture and storage (CCS) are included in the modeling, though these units are expected to be compliant with the applicable standards under this rule. Because this rule does not change these forecasts, it is expected to have no, or negligible, costs[7] or quantified benefits.

New non-compliant coal-fired units are not expected to be constructed in the baseline, due in part to the low cost of constructing and operating new NGCC units relative to the cost of new coal-fired units, relatively low forecast growth in electricity demand, and an expectation that the growth in end-use energy efficiency and renewable energy resources will continue. The expectation that no new non-compliant coal-fired units will be constructed in the baseline, and

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[6] See the EIA's 2009 to 2015 Annual Energy Outlooks (AEO).

[7] Any additional monitoring or reporting costs from this rule should be negligible because new generators would already be required to monitor and report their CO_2 emissions under the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98). Costs are only incurred if there has been a violation of an emission standard caused by a malfunction and a source chooses to assert an affirmative defense. The owner/operator must meet the burden of proving all of the requirements in an affirmative defense. See Chapter 7 for more details on monitoring and reporting costs.

therefore that the promulgated standard of performance would not be a factor in decisions to construct, holds under a range of alternative baseline scenarios.

Natural gas-fired combustion turbine units intended to serve as intermediate and base load generators constructed in the baseline are expected to be compliant with the standard, due in part to the cost-effectiveness of constructing and operating new combined cycle units relative to the cost of new simple cycle units. Absent significantly lower natural gas prices, the cost of electricity generated by combined cycle units operating at intermediate and base load capacity are lower than simple cycle units operating at the same capacity factor.

Chapter 5 complements and extends the sector level analysis by examining conditions (e.g., significantly higher natural gas prices) in which conclusions regarding the future economic competitiveness of new non-compliant coal-fired units relative to other new generation technologies may differ from those in the sector-wide analysis. The analysis evaluates the cost and benefits of adopting different competing generating technologies to serve base load demand at an individual facility level. When considering a wide range of natural gas price assumptions, along with information on historical and projected gas prices, this illustrative facility-level analysis supports the conclusion that these final standards are highly likely to incur no costs or quantified benefits. Furthermore, the analysis examines the costs and benefits that would occur in the unlikely case where an investor might choose to construct new coal-fired capacity, and shows that the result is a net monetized benefits to society under a range of assumptions.

As described in Chapter 6, the EPA has reached a similar conclusion for the reconstruction and modification provisions for both steam generating units and stationary combustion turbines. The EPA has historically been notified of few modifications or reconstructions under the NSPS provisions and, as such, anticipates few covered units will trigger the NSPS reconstruction or modification provisions in the period of analysis. As a result, we do not anticipate any significant costs or benefits associated with this rule.

1.2 Background for the Final EGU New, Modified, and Reconstructed Source GHG Standards

1.2.1 Baseline and Years of Analysis

The standards on which this analysis is based set GHG emission limits for new, modified, and reconstructed fossil fuel-fired EGUs. The baseline for this analysis, which uses the Integrated Planning Model (IPM), includes state rules that have been finalized and/or approved by a state's legislature or environmental agency as well as final federal rules. Additional legally binding and enforceable commitments for GHG reductions considered in the baseline are discussed in Chapter 4 of this RIA.

All analyses are presented for compliance through the year 2022[8] and all estimates are presented in 2011 dollars. CAA Section 111(b) requires that the NSPS be reviewed every eight years. As a result, this analysis is primarily focused on projected impacts within the current eight-year NSPS timeframe. The EPA's finding of no new non-compliant units (and therefore, no projected costs or quantified benefits) is robust beyond the analysis period (past 2030) in both the IPM base case and the EIA's Annual Energy Outlook 2014 Reference Case modeling projections. Furthermore, this finding is robust in the analysis period across a wide range of alternative potential market, technical, and regulatory scenarios that influence power sector investment decisions evaluated by EIA.[9] Chapter 5 complements and extends the sector level analysis by examining conditions (e.g., significantly high natural gas prices) in which these conclusions regarding the future economic competitiveness of new non-compliant coal-fired units relative to other new generation technologies may differ. The analysis evaluates the cost and benefits of adopting different competing generating technologies to serve base load demand at an individual facility level.

Benefits and costs presented in the illustrative analyses in Chapter 5 of this RIA represent estimates from emission reductions under the finalized standards in a particular year. The latent and/or ongoing damages associated with pollution from these sources in a particular analysis year are discounted to the analysis year.[10] The benefits and costs presented do not represent the net present value of a stream of benefits and costs due to emission reductions over time.

[8] In IPM, conditions in the analysis year of 2022 are represented by a model year of 2020.

[9] For example, in the 2014 AEO low gas resource sensitivity case, one of the scenarios most favorable to the construction of new coal capacity, the operation of new non-compliant coal capacity in the baseline is not forecast by the model until 2027.

[10] The CO_2-related benefits, which are estimated using the social cost of carbon, vary depending on the year in which the change in CO_2 emissions occurs. The social cost of carbon increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change. The EPA relied on a national-average benefit per-ton method to estimate $PM_{2.5}$-related health impacts of SO_2 and NO_X emissions. Despite our attempts to quantify and monetize as many of the co-benefits of reducing emissions from electricity generating sources as possible, not all known health and non-health co-benefits are accounted for in this assessment. See Chapter 3 for details.

1.2.2 Definition of Affected EGUs

1.2.2.1 New Sources

The statutory authority for this action is CAA section 111(b), which addresses standards of performance for new, modified, and reconstructed sources. The final standards for newly constructed fossil fuel-fired EGUs apply to those sources that commenced construction on or after January 8, 2014.

1.2.2.2 Modified Sources

A modification is any physical or operational change to a source that increases the amount of any air pollutant emitted by the source or results in the emission of any air pollutant not previously emitted. The final standards for modified fossil fuel-fired steam generating units apply to those sources that make modifications resulting in an increase of hourly CO_2 emissions of more than 10 percent on or after June 18, 2014. However, projects to install pollution controls required under other CAA provisions are specifically exempted from the definition of "modifications" under 40 CFR 60.14(e)(5), even if they emit CO_2 as a byproduct.

1.2.2.3 Reconstructed Sources

The EPA's CAA section 111 regulations provide that reconstructed sources are to be treated as new sources and, therefore, subject to new source standards of performance. The regulations define reconstructed sources, in general, as existing sources: (i) that replace components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility and (ii) for which compliance with standards of performance for new sources is technologically and economically feasible (40 CFR 60.15). The final standards for reconstructed fossil fuel-fired EGUs apply to those sources that reconstruct on or after June 18, 2014.

1.2.3 Regulated Pollutant

These final standards set limits for emissions of CO_2 from affected EGUs. The EPA is aware that other GHGs such as nitrous oxide (N_2O) and to a lesser extent, methane (CH_4), may be emitted from fossil-fuel-fired EGUs, especially from coal-fired circulating fluidized bed combustors and from units with selective catalytic reduction and selective non-catalytic reduction systems installed for nitrogen oxide (NO_X) control. The EPA is not setting separate N_2O or CH_4 emission limits or an equivalent CO_2 emission limit because of a lack of available data for these affected EGUs. Additional information on the quantity and significance of emissions and on the availability of cost effective controls would be needed before setting standards for these pollutants.

1.2.4 Emission Limits

The EPA has determined that the BSER for newly constructed steam generating units is a supercritical pulverized coal (SCPC) unit with post-combustion partial CCS technology. The standard of performance achievable using that BSER is 1,400 lb CO_2/MWh-gross. The standard for modified steam generating units that conduct modifications resulting in a potential hourly increase in CO_2 emissions (mass per hour) of more than 10 percent[11] is a unit-specific emission limitation consistent with each modified unit's best one-year historical performance during the years from 2002 to the time of the modification. For reconstructed steam generating units, the BSER is the most efficient demonstrated generating technology for these types of units (i.e., meeting a standard of performance consistent with a reconstructed boiler using most efficient steam conditions available, even if the boiler was not originally designed to do so).

The BSER for new, modified, and reconstructed primarily natural gas-fired combustion turbines expected to serve intermediate and base load is the use of well-designed, well-maintained, and well-operated natural gas combined cycle (NGCC) technology. The standard of performance achievable using that BSER is 1,000 lb/CO_2/MWh-gross.

The applicability of these standards is based on the capacity and operation of a source and is described in the preamble for this final rule. The final standards will be met on a 12-operating month rolling average basis. The BSER determination and final standards for each affected EGU are shown in Table 1-1.

Table 1-1. Summary of BSER and Final Standards for Affected EGUs

Affected EGU	BSER	Standard
Newly Constructed Fossil Fuel-Fired Steam Generating Units	Efficient new SCPC utility boiler implementing partial CCS	1,400 lb CO_2/MWh-gross
Modified Fossil Fuel-Fired Steam Generating Units	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades	Sources making modifications resulting in an increase in CO_2 hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,800 lb CO_2/MWh-gross for

[11] More than 10 percent as compared to its highest potential to emit in the past 5 years. The EPA is deferring issuing standards for units that conduct modifications with a potential hourly increase in CO_2 of 10 percent or less.

		sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.
Reconstructed Fossil Fuel-Fired Steam Generating Units	Most efficient generating technology at the affected EGU.	1. 1,800 lb CO_2/MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.
Newly Constructed and Reconstructed Natural Gas-Fired Stationary Combustion Turbines	Efficient NGCC technology for natural gas-fired base load units and clean fuels for non-base load and multi-fuel-fired units.	4. 1,000 lb CO_2/MWh-gross or 1,030 lb CO_2/MWh-net for base load natural gas-fired units. 5. 120 lb CO_2/MMBtu for non-base load natural gas-fired units. 6. 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units.

1.2.5 Emission Reductions

As will be discussed in more detail in Chapter 4 of this RIA, the EPA anticipates that the EGU New, Modified, and Reconstructed Source GHG Standards will result in negligible changes in GHG emissions over the analysis period. The EPA expects that owners of new units will choose generation technologies that meet these standards in the baseline due to expected economic conditions in the marketplace. Based on historical precedent, the EPA anticipates few covered units will trigger the NSPS reconstruction or modification provisions in the period of analysis. As a result, we do not anticipate any significant costs or monetized benefits associated with this rule.

1.3 Organization of the Regulatory Impact Analysis

This report presents the EPA's analysis of the potential benefits, costs, and other economic effects of the EGU New, Modified, and Reconstructed Source GHG Standards to fulfill the requirements of an RIA. This RIA includes the following chapters:

- Chapter 2, Electric Power Sector Profile, describes the industry affected by the rule.
- Chapter 3, Benefits of Reducing GHGs and Other Pollutants, describes the effects of

emissions on climate and health and provides background information to support the benefits analysis.

- Chapter 4, Costs, Economic, and Energy Impacts of the New Source Standards, describes impacts of the rule for new sources.
- Chapter 5, Analysis of Illustrative Benefit-Cost Scenarios for New Sources, describes additional analyses examining potential impacts under a range of scenarios.
- Chapter 6, Modified and Reconstructed Sources, describes the potential impacts of the standards for modified and reconstructed sources.
- Chapter 7, Statutory and Executive Order Impact Analyses, describes the small business, unfunded mandates, paperwork reduction act, environmental justice, and other analyses conducted for the rule to meet statutory and Executive Order requirements.

CHAPTER 2
ELECTRIC POWER SECTOR PROFILE

2.1 Introduction

This chapter discusses important aspects of the power sector that relate to the EGU New, Modified and Reconstructed Source GHG Standards, including the types of electricity generating units (EGUs) affected by the regulation, and provides background on the power sector and EGUs. In addition, this chapter provides some historical background on trends in the past decade in the power sector, as well as about existing U.S. Environmental Protection Agency (EPA) regulation of the power sector.

In the past decade there have been significant structural changes in the both the mix of generating capacity and in the share of electricity generation supplied by different types of generation. These changes are the result of multiple factors in the power sector, including normal replacements of older generating units with new units, changes in the electricity intensity of the U.S. economy, growth and regional changes in the U.S. population, technological improvements in electricity generation from both existing and new units, changes in the prices and availability of different fuels, and substantial growth in electricity generation by renewable and unconventional methods. Many of these trends will continue to contribute to the evolution of the power sector. The evolving economics of the power sector, in particular the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more gas being utilized as base load energy in addition to supplying electricity during peak load. This chapter presents data on the evolution of the power sector from 2002 through 2012. Projections of new capacity and the impact of this rule on these new sources are discussed in more detail in Chapter 4 of this Regulatory Impact Assessment (RIA).

2.2 Power Sector Overview

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution.

2.2.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. There are two important aspects of electricity generation: capacity and net generation. Generating capacity refers to the maximum amount of production from an EGU in a typical hour, typically measured in megawatts (MW) or gigawatts (1 GW = 1,000 MW). Electricity generation refers to the amount of electricity actually produced by EGUs, measured in kilowatt-hours (kWh) or gigawatt-hours (GWh = 1 million kWh). In addition to producing electricity for sale to the grid, generators perform other services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators. Other important services provided by generators include facilitating the regulation of the voltage of supplied generation.

Individual EGUs are not used to generate electricity 100 percent of the time. Individual EGUs are periodically not needed to meet the regular daily and seasonal fluctuations of electricity demand. Furthermore, EGUs relying on renewable resources such as wind, sunlight, and surface water to generate electricity are routinely constrained by the availability of adequate wind, sunlight, or water at different times of the day and season. Units are also unavailable during routine and unanticipated outages for maintenance. These factors result in the mix of generating capacity types available (i.e., the share of capacity of each type of EGU) being substantially different than the mix of the share of total electricity produced by each type of EGU in a given season or year.

Most of the existing capacity generates electricity by creating heat to generate high pressure steam that is released to rotate turbines which, in turn, create electricity. Natural gas combined cycle (NGCC) units have two generating components operating from a single source of heat. The first cycle is a gas-fired turbine, which generates electricity directly from the heat of burning natural gas. The second cycle reuses the waste heat from the first cycle to generate steam, which is then used to generate electricity from a steam turbine. Other EGUs generate electricity by using water or wind to rotate turbines, and a variety of other methods also make up a small, but growing, share of the overall electricity supply. The generating capacity includes fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources (see Table 2-1). Table 2-1 also shows the comparison between the generating capacity in 2002 and 2012.

In 2012, the power sector consisted of over 19,000 generating units with a total capacity[12] of 1,168 GW, an increase of 188 GW (or 19 percent) from the capacity in 2002 (980 GW). The 188 GW increase consisted primarily of natural gas fired EGUs (134 GW) and wind generators (55 GW), with substantially smaller net increases and decreases in other types of

[12] As with all data presented in this section, this includes generating capacity not only at EGUs primarily operated to supply electricity to the grid, but also generating capacity at commercial and industrial facilities that produce both electricity used onsite as well as dispatched to the grid. Unless otherwise indicated, capacity data presented in this RIA is installed nameplate capacity (also known as nominal capacity), defined by EIA as "The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer." Nameplate capacity is consistently reported to regulatory authorities with a common definition, where alternate measures of capacity (e.g., net summer capacity and net winter capacity) can use a variety of definitions and specified conditions.

generating units.

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Table 2-1. Existing Electricity Generating Capacity by Energy Source, 2002 and 2012

	2002		2012		Change Between '02 and '12		
Energy Source	Generator Nameplate Capacity (MW)	% Total Capacity	Generator Nameplate Capacity (MW)	% Total Capacity	% Increase	Nameplate Capacity Change (MW)	% of Total Capacity Increase
Coal	338,199	35%	336,341	29%	-1%	-1,858	-1%
Natural Gas[1]	352,128	36%	485,957	42%	38%	133,829	71%
Nuclear	104,933	11%	107,938	9%	3%	3,005	2%
Hydro	96,344	10%	99,099	8%	3%	2,755	1%
Petroleum	66,219	7%	53,789	5%	-19%	-12,430	-7%
Wind	4,531	0.5%	59,629	5.1%	1216%	55,098	29%
Other Renewable	14,208	1.5%	20,986	1.8%	47.7%	6,778	3.6%
Misc	3,023	0.3%	4,257	0.4%	40.8%	1,234	0.7%
Total	979,585	100%	1,167,995	100%	19%	188,410	100%

Note: This table presents generation capacity. Actual net generation is presented in Table 2-2.

Source: U.S. EIA Electric Power Annual, 2014. Downloaded from EIA Electricity Data Browser, Electric Power Plants Generating Capacity By Source, 2000 – 2013. Available at http://www.eia.gov/electricity/data.cfm#gencapacity.

[1] Natural Gas information in this chapter (unless otherwise stated) reflects data for all generating units using natural gas as the primary fossil heat source. This includes Combined Cycle Combustion Turbine (31 percent of 2012 NG-fired capacity), Gas Turbine (30 percent), Combined Cycle Steam (19 percent), Steam Turbine (17 percent), and miscellaneous (< 1 percent).

The 19 percent increase in generating capacity is the net impact of newly built generating units, retirements of generating units, and a variety of increases and decreases to the nameplate capacity of individual existing units due to changes in operating equipment, changes in emission controls, etc. During the period 2002 to 2012, a total of 315,752 MW of new generating capacity was built and brought online, and 64,763 MW existing units were retired. The net effect of the re-rating of existing units reduced the total capacity by 62,579 MW. The overall net change in capacity was 188,410 MW, as shown in Table 2-1.

The newly built generating capacity was primarily natural gas (226,605 MW), which was partially offset by gas retirements (29,859 MW). Wind capacity was the second largest type of new builds (55,583 MW), augmented by 2,807 MW of solar.[14] The overall mix of newly built and retired capacity, along with the net effect, is shown on Figure 2-1.

[14] Partially offset by 87 MW retired wind or solar capacity.

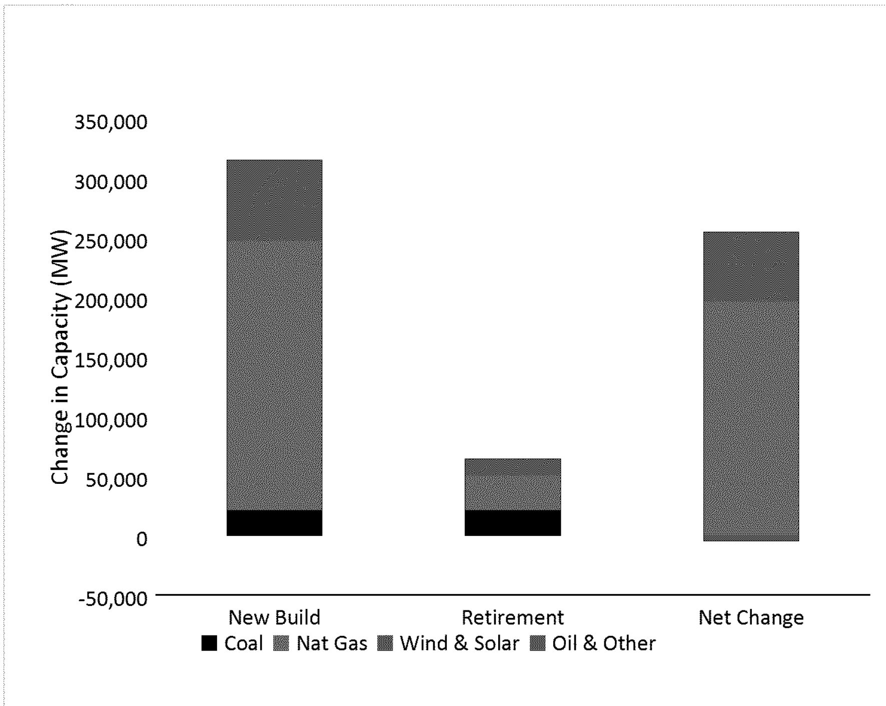


Figure 2-1. New Build and Retired Capacity (MW) by Fuel Type, 2002-2012
Source: EIA Form 860
Not displayed: wind and solar retirements = 87 MW, net change in coal capacity = -56 MW

In 2012, electric generating sources produced a net 4,058 trillion kWh to meet electricity demand, a 5 percent increase from 2002 (3,858 trillion kWh). As presented in Table 2-2, almost 70 percent of electricity in 2012 was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for the largest single share. Although the share of the total generation from fossil fuels in 2012 (67 percent) was only modestly smaller than the total fossil share in 2002 (71 percent), the mix of fossil fuel generation changed substantially during that period. Coal generation declined by 18 percent and petroleum generation by 72 percent, while natural gas generation increased by 60 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. Wind generation also grew from a very small portion of the overall total in 2002 to 4.1 percent of the 2012 total.

Table 2-2. Net Generation in 2002 and 2012 (Trillion kWh = TWh)

	2002	2012	Change Between '02 and '12

	Net Generation (TWh)	Fuel Source Share	Net Generation (TWh)	Fuel Source Share	Net Generation Change (TWh)	% Change in Net Generation
Coal	1,933.1	50%	1,586.0	39%	-347.1	-18.0%
Natural Gas	702.5	18%	1,125.9	28%	423.5	60.3%
Nuclear	780.1	20%	789.0	19%	9.0	1.1%
Hydro	255.6	7%	264.7	7%	9.1	3.6%
Petroleum	94.6	2.5%	26.9	0.7%	-67.7	-71.6%
Wind	10.4	0.3%	167.7	4.1%	157.3	1519.3%
Other Renewable	68.8	1.8%	85.7	2.1%	16.9	24.6%
Misc	13.5	0.4%	12.4	0.3%	-1.2	-8.7%
Total	**3,858**	**100%**	**4,058**	**100%**	**200**	**5%**

Source: U.S. EIA Monthly Energy Review, December 2014. Table 7.2a Electricity Net Generation: Total (All Sectors). Available at http://www.eia.gov/totalenergy/data/monthly/. Accessed 12/19/2014

Coal-fired and nuclear generating units have historically supplied "base load" electricity, the portion of electricity loads which are continually present, and typically operate throughout all hours of the year. The coal units meet the part of demand that is relatively constant. Although much of the coal fleet operates as base load, there can be notable differences across various facilities (see Table 2-3). For example, coal-fired units less than 100 megawatts (MW) in size compose 37 percent of the total number of coal-fired units, but only 6 percent of total coal-fired capacity. Gas-fired generation is better able to vary output and is the primary option used to meet the variable portion of the electricity load and has historically supplied "peak" and "intermediate" power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced.

Table 2-3 also shows comparable data for the capacity and age distribution of natural gas units. Compared with the fleet of coal EGUs, the natural gas fleet is generally smaller and newer. While 55 percent of the coal EGU fleet is over 500 MW per unit, 77 percent of the gas fleet is between 50 and 500 MW per unit. Many of the largest gas units are gas-fired steam-generating EGUs.

Table 2-3. Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Thermal Efficiency (Heat Rate)

Unit Size Grouping (MW)	No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
COAL							
0 – 24	223	18%	40.7	11.4	2,538	1%	11,733
25 – 49	108	9%	44.2	36.7	3,963	1%	11,990
50 – 99	157	12%	49.0	74.1	11,627	4%	11,883
100 - 149	128	10%	50.6	122.7	15,710	5%	10,971
150 - 249	181	14%	48.7	190.4	34,454	11%	10,620
250 - 499	205	16%	38.4	356.2	73,030	23%	10,502
500 - 749	187	15%	35.4	604.6	113,056	36%	10,231
750 - 999	57	5%	31.4	823.9	46,963	15%	9,942
1000 - 1500	11	1%	35.7	1259.1	13,850	4%	9,732
Total Coal	1257	100%	42.6	250.7	315,191	100%	11,013
NATURAL GAS							
0 – 24	1992	37%	37.6	7.0	13,863	3%	13,531
25 – 49	410	8%	21.8	125.0	51,247	12%	9,690
50 - 99	962	18%	15.6	174.2	167,536	39%	8,489
100 - 149	802	15%	23.4	39.9	31,982	8%	11,765
150 - 249	167	3%	28.7	342.4	57,179	13%	9,311
250 - 499	982	18%	24.6	71.1	69,788	16%	12,083
500 - 749	37	1%	40.0	588.8	21,785	5%	11,569
750 - 1000	14	0.3%	35.9	820.9	11,492	3%	10,478
Total Gas	5366	100%	27.7	79.2	424,872	100%	11,652

Source: National Electric Energy Data System (NEEDS) v.5.14

Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency. Table is limited to coal-steam units in operation in 2013 or earlier, and excludes those units in NEEDS with planned retirements in 2014 or 2015.

In terms of the age of the generating units, 50 percent of the total coal generating capacity has been in service for more than 38 years, while 50 percent of the natural gas capacity has been in service less than 15 years. Figure 2-2 presents the cumulative age distributions of the coal and gas fleets, highlighting the pronounced differences in the ages of the fleets of these two types of fossil-fuel generating capacity. Figure 2-2 also includes the distribution of generation.

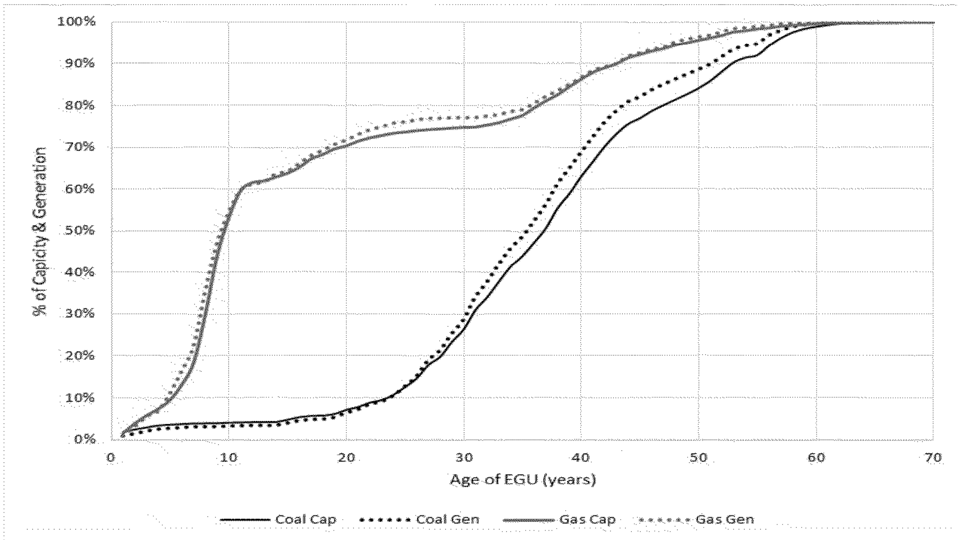


Figure 2-2. Cumulative Distribution in 2010 of Coal and Natural Gas Electricity Capacity and Generation, by Age

Source: National Electric Energy Data System (NEEDS) v.5.13

Not displayed: coal units (376 MW total, 1 percent of total) and gas units (62 MW, < .01 percent of total)) over 70 years old for clarity. Figure is limited to coal-steam units in NEEDS v.5.13 in operation in 2013 or earlier (excludes ~2,100 MW of coal-fired IGCC and fossil waste capacity), and excludes those units in NEEDS with planned retirements in 2014 or 2015.

The locations of existing fossil units in the EPA's National Electric Energy Data System (NEEDS) v.5.13 are shown in Figure 2-3.

Figure 2-3. Fossil Fuel-Fired Electricity Generating Facilities, by Size
Source: National Electric Energy Data System (NEEDS) v.5.13

Note: This map displays fossil capacity at facilities in the NEEDS v.5.13 IPM frame. NEEDS v.5.13 reflects generating capacity expected to be online at the end of 2015. This includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

2.2.2 Transmission

Transmission is the term used to describe the bulk transfer of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,[15] each operating synchronously. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator. In others, individual utilities coordinate the operation of their generation,

[15] These three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Electric Reliability Council of Texas (ERCOT) Interconnection, comprising most of Texas. See map of all NERC interconnections at http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Interconnections_Color_072512.jpg

transmission, and distribution systems to balance their common generation and load needs.

2.2.3 Distribution

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution system is the classic example of a natural monopoly, in part because it is not practical to have more than one set of lines running from the electricity generating sources to substations or from substations to residences and businesses.

Over the last couple of decades, several jurisdictions in the United States began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, the transmission system had been developed by vertically integrated utilities, establishing much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, electric cooperatives, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by a number of utilities that purchase and sell electricity, but do not generate it. As discussed below, electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

2.3 Sales, Expenses, and Prices

These electric generating sources provide electricity for ultimate commercial, industrial, and residential customers. Each of the three major categories of ultimate customers consume roughly a quarter to a third of the total electricity produced[16] (see Table 2-4). Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2002 and 2012.

[16] Transportation (primarily urban and regional electrical trains) is a fourth ultimate customer category which accounts less than one percent of electricity consumption.

Table 2-4. Total U.S. Electric Power Industry Retail Sales in 2012 (billion kWh)

		2002		2012	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,265	35%	1,375	35.9%
	Commercial	1,104	30%	1,327	34.6%
	Industrial	990	27%	986	25.7%
	Transportation	NA	-	7	0.2%
	Other	106	3%	NA	-
Total		3,465	95%	3,695	96%
Direct Use		166	5%	138	4%
Total End Use		**3,632**	100%	**3,832**	100%

Source: Table 2.2, EIA Electric Power Annual, 2013
Notes:

Retail sales are not equal to net generation (Table 2-2) because net generation includes net exported electricity and loss of electricity that occurs through transmission and distribution.

Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.

2.3.1 Electricity Prices

Electricity prices vary substantially across the United States, differing both between the ultimate customer categories and also by state and region of the country. Electricity prices are typically highest for residential and commercial customers because of the relatively high costs of distributing electricity to individual homes and commercial establishments. The high prices for residential and commercial customers are the result both of the necessary extensive distribution network reaching to virtually every part of the country and every building, and also the fact that generating stations are increasingly located relatively far from population centers, which increases transmission costs. Industrial customers generally pay the lowest average prices, reflecting both their proximity to generating stations and the fact that industrial customers receive electricity at higher voltages, which makes transmission more efficient and less expensive). Industrial customers frequently pay variable prices for electricity by the season and time of day, while residential and commercial prices historically have been less variable. Overall industrial customer prices are usually considerably closer to the wholesale marginal cost of generating electricity than residential and commercial prices.

On a state-by-state basis, all retail electricity prices vary considerably. In 2011 the national average retail electricity price (all sectors) was 9.90 cents/KWh, with a range from 6.44 cents (Idaho) to 31.59 cents (Hawaii). The Northeast, California, and Alaska have average retail prices that can be as much as double those of other states (see Figure 2-4), and Hawaii has the most expensive retail price of electricity in the country.

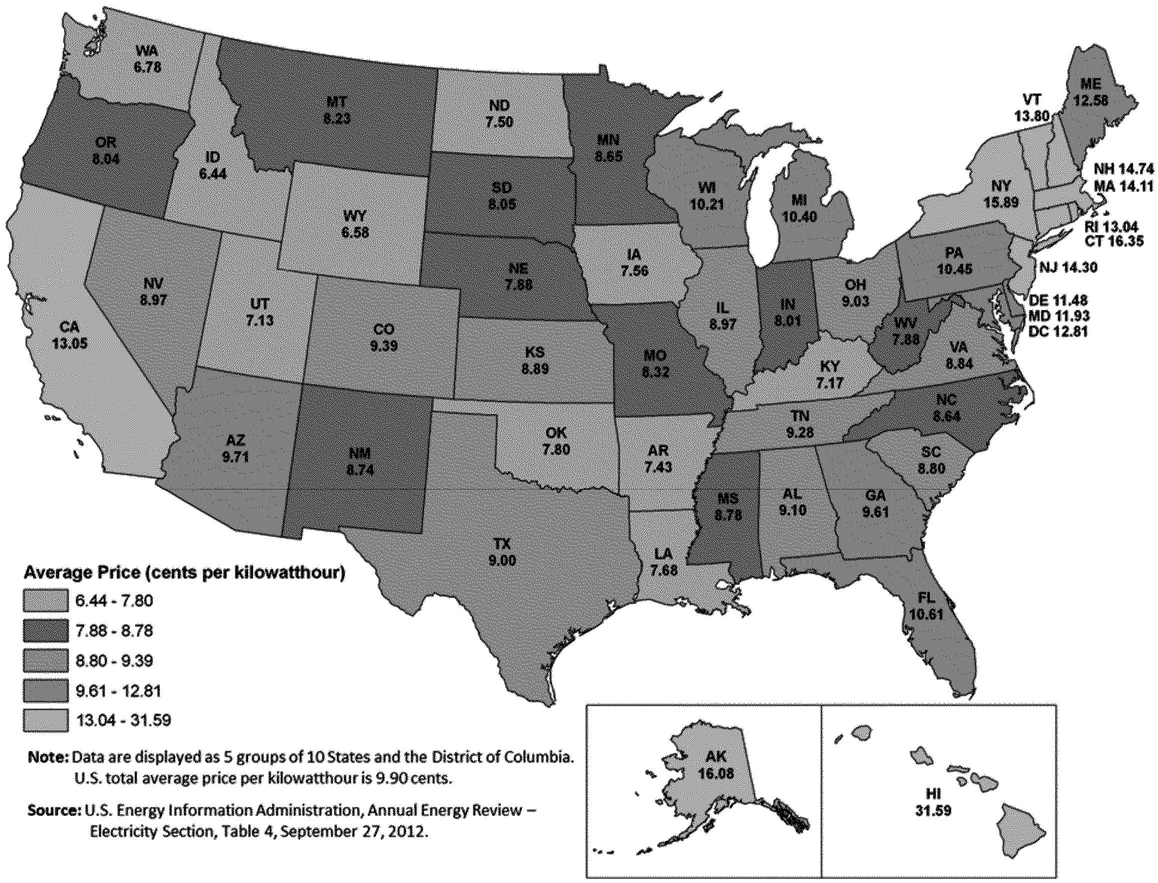


Figure 2-4. Average Retail Electricity Price by State (cents/kWh), 2011

Average national retail electricity prices increased between 2002 and 2012 by 36.7 percent in nominal (current year $) terms. The amount of increase differed for the three major end use categories (residential, commercial and industrial). National average residential prices increased the most (40.8 percent), and commercial prices increased the least (27.9 percent). The nominal year prices for 2002 through 2012 are shown in Figure 2-5.

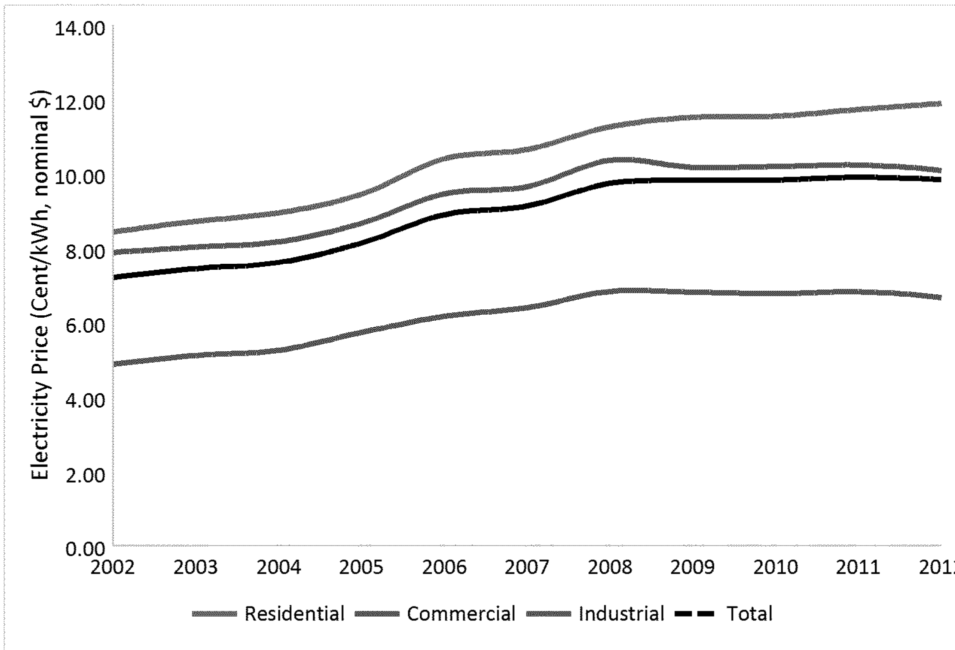


Figure 2-5. Nominal National Average Electricity Prices for Three Major End-Use Categories

Source: EIA AEO 2012, Table 2.4

Electricity prices for all three end-use categories increased more than overall inflation through this period, measured by either the Gross Domestic Product (GDP) implicit price deflator (23.5 percent) or the consumer price index (CPI-U, which increased by 27.7 percent)[17]. Most of these electricity price increases occurred between 2002 and 2008. Since 2008 nominal electricity prices have been relatively stable while overall inflation continued to increase. The increase in nominal electricity prices for the major end use categories, as well as increases in the GDP price and CPI-U indices for comparison, are shown in Figure 2-6.

[17] Source: Federal Reserve Economic Data, FRB St. Louis. Available at http://research.stlouisfed.org/fred2/.

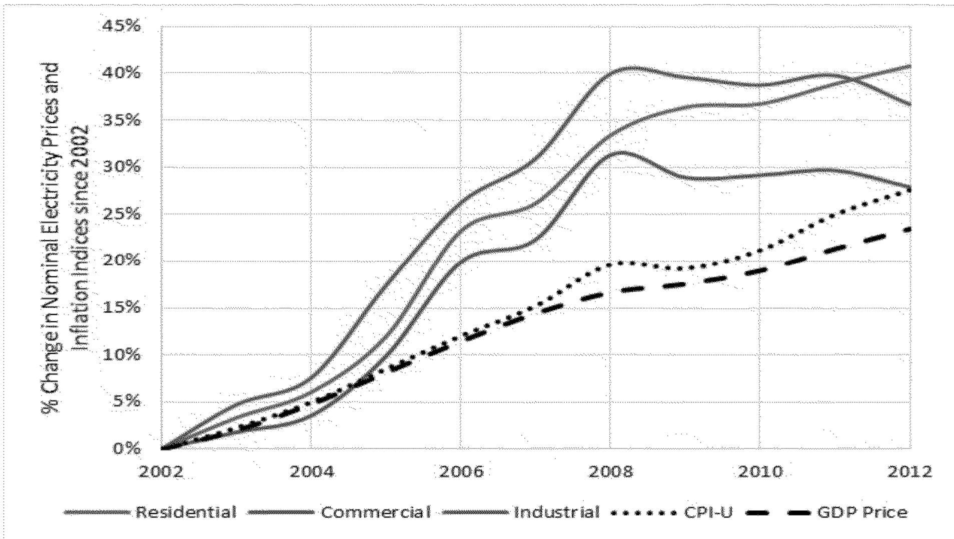


Figure 2-6. Relative Increases in Nominal National Average Electricity Prices for Major End-Use Categories, with Inflation Indices

The real (inflation-adjusted) change in average national electricity prices can be calculated using the GDP implicit price deflator. Figure 2-7 shows real[18] (2011$) electricity prices for the three major customer categories from 1960 to 2012, and Figure 2-8 shows the relative change in real electricity prices relative to the prices in 1960. As can be seen in the figures, the price for industrial customers has always been lower than for either residential or commercial customers, but the industrial price has been more volatile. While the industrial real price of electricity in 2012 was relatively unchanged from 1960, residential and commercial real prices are 23 percent and 28 percent lower respectively than in 1960.

[18] All prices in this section are estimated as real 2011 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

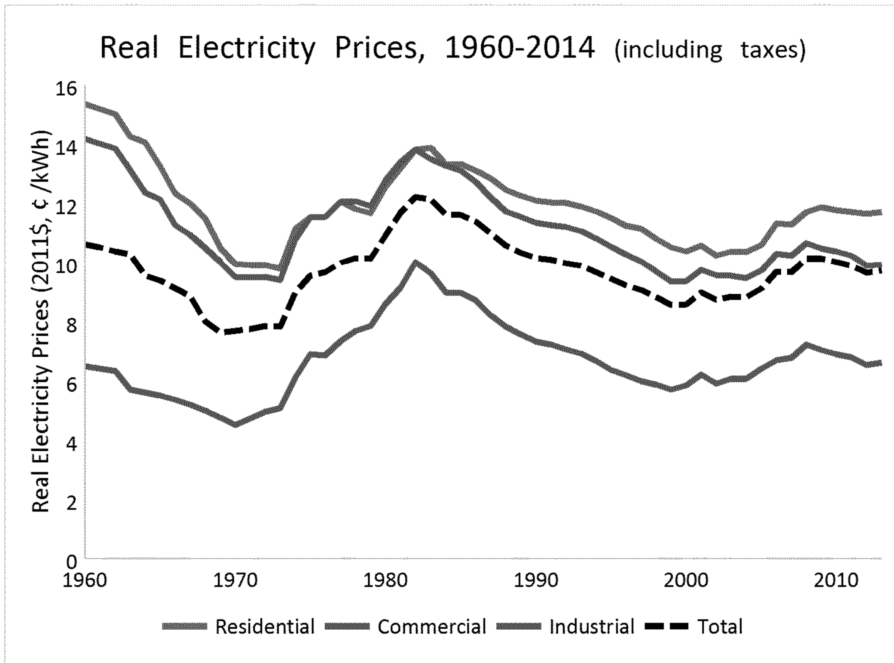


Figure 2-7. Real National Average Electricity Prices (2011$) for Three Major End-Use Categories

Source: EIA Monthly Energy Review, April 2015, Table 9.8

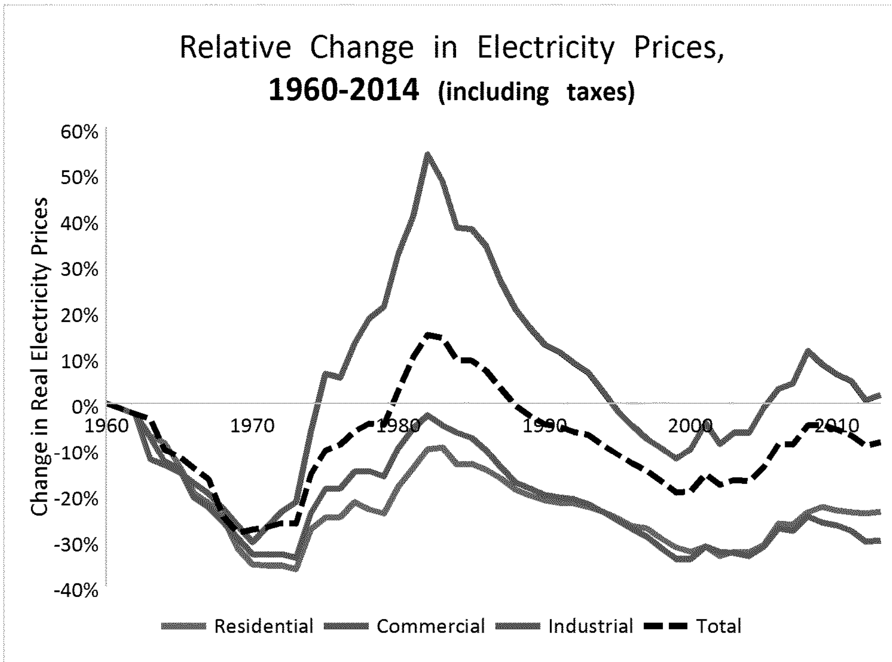


Figure 2-8. Relative Change in Real National Average Electricity Prices (2011$) for Three Major End-Use Categories

Source: EIA Monthly Energy Review, April 2015, Table 9.8

2.3.2 Prices of Fossil Fuels Used for Generating Electricity

Another important factor in the changes in electricity prices are the changes in fuel prices for the three major fossil fuels used in electricity generation: coal, natural gas and oil. Relative to real prices in 2002, the national average real price (in 2011$) of coal delivered to EGUs in 2012 had increased by 54 percent, while the real price of natural gas decreased by 22 percent. The real price of oil increased by 203 percent, but with oil declining as an EGU fuel (in 2012 oil generated only 1 percent of electricity) the doubling of oil prices had little overall impact in the electricity market. The combined real delivered price of all fossil fuels in 2012 increased by 23 percent over 2002 prices. Figure 2-9 shows the relative changes in real price of all three fossil fuels between 2002 and 2012.

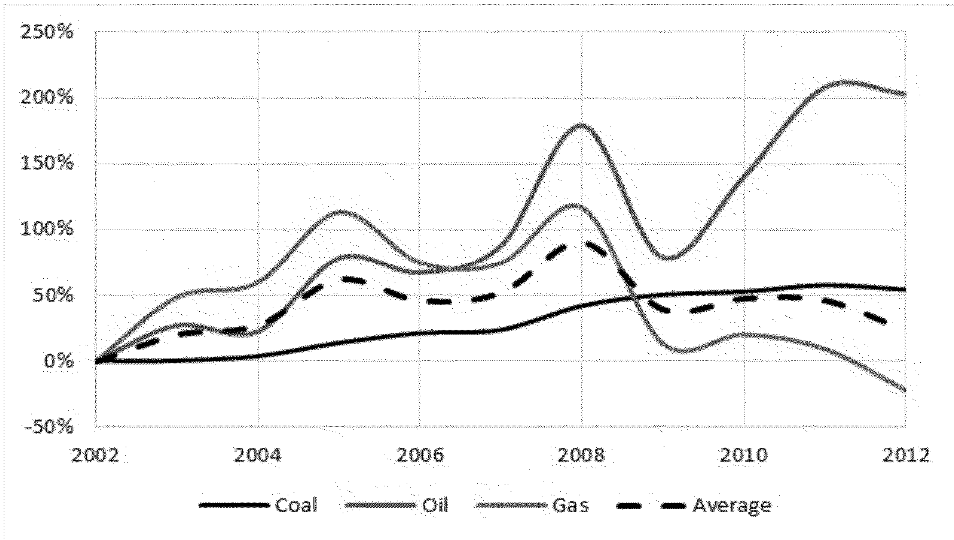


Figure 2-9. Relative Real Prices of Fossil Fuels for Electricity Generation and Change in National Average Real Price per MBtu Delivered to EGU
Source: EIA AEO 2012, Table 9.9

2.3.3 Changes in Electricity Intensity of the U.S. Economy Between 2002 to 2012

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2002 and 2012 is that while total net generation increased by 4.9 percent over that period, the demand growth for generation has been low, and in fact was lower than both the population growth (9.2 percent) and real GDP growth (19.8 percent). Figure 2-10 shows the growth of electricity generation, population and real GDP during this period.

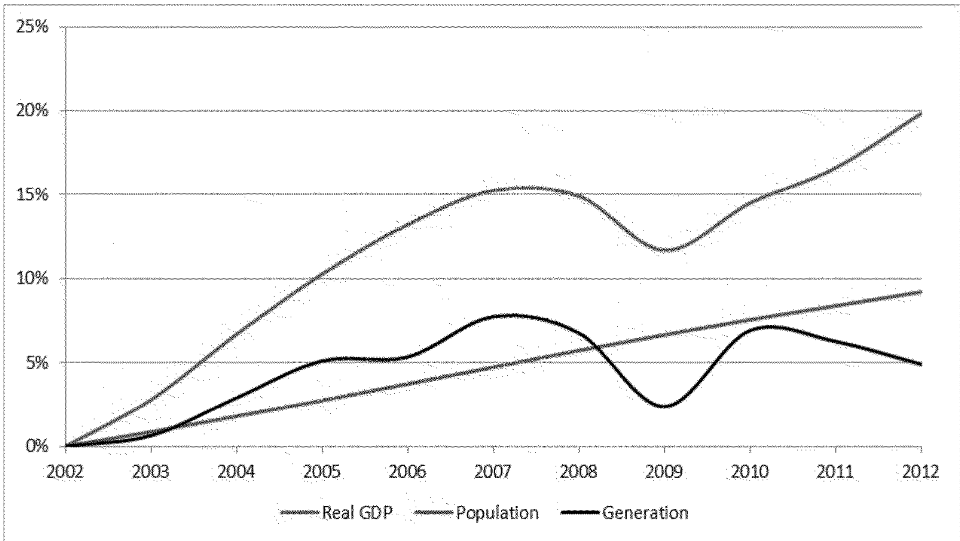


Figure 2-10. Relative Growth of Electricity Generation, Population, and Real GDP Since 2002
Sources: U.S. EIA Monthly Energy Review, December 2014. Table 7.2a Electricity Net Generation: Total (All Sectors). U.S. Census.

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2002 to 2012. On a per capita basis, real GDP per capita grew by 10.9 percent, increasing from $44,900 (in 2011$) per person in 2002 to $49,800 per person in 2012. At the same time electricity generation per capita decreased by 3.9 percent, declining from 13.4 MWh per person in 2002 to 12.8 MWh per person in 2012. The combined effect of these two changes improved the overall electricity efficiency of the U.S. economy. Electricity generation per dollar of real GDP decreased 12.5 percent, declining from 299 MWh per $1 million of GDP to 261 MWh per $1 million GDP. These relative changes are shown in Figure 2-11. Figures 2-10 and 2-11 clearly show the effects of the 2007 – 2009 recession on both GDP and electricity generation, as well as the effects of the subsequent economic recovery.

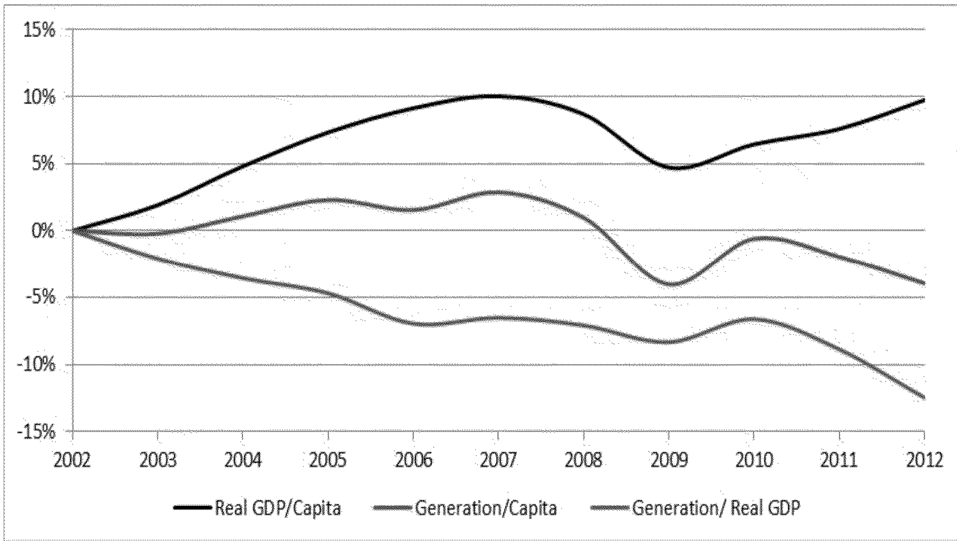


Figure 2-11. Relative Change of Real GDP, Population, and Electricity Generation Intensity Since 2002

Sources: U.S. EIA Monthly Energy Review, December 2014. Table 7.2a Electricity Net Generation: Total (All Sectors). U.S. Census

2.4 Deregulation and Restructuring

The process of restructuring and deregulation of wholesale and retail electric markets has changed the structure of the electric power industry. In addition to reorganizing asset management between companies, restructuring sought a functional unbundling of the generation, transmission, distribution, and ancillary services the power sector has historically provided, with the aim of enhancing competition in the generation segment of the industry.

Beginning in the 1970s, government policy shifted against traditional regulatory approaches and in favor of deregulation for many important industries, including transportation (notably commercial airlines), communications, and energy, which were all thought to be natural monopolies (prior to 1970) that warranted governmental control of pricing. However, deregulation efforts in the power sector were most active during the 1990s. Some of the primary drivers for deregulation of electric power included the desire for more efficient investment choices, the economic incentive to provide least-cost electric rates through market competition, reduced costs of combustion turbine technology that opened the door for more companies to sell power with smaller investments, and complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes. Deregulation and market restructuring in the power sector involved the divestiture of generation from utilities, the formation of organized wholesale spot energy markets with economic mechanisms for the rationing of scarce transmission resources during periods of peak demand, the introduction of retail choice programs, and the establishment of new forms of market oversight and coordination.

The pace of restructuring in the electric power industry slowed significantly in response to market volatility in California and financial turmoil associated with bankruptcy filings of key energy companies. By the end of 2001, restructuring had either been delayed or suspended in eight states that previously enacted legislation or issued regulatory orders for its implementation (shown as "Suspended" in Figure 2-12). Eighteen other states that had seriously explored the possibility of deregulation in 2000 reported no legislative or regulatory activity in 2001 (EIA, 2003) ("Not Active" in Figure 2-12). Currently, there are 15 states plus the District of Columbia where price deregulation of generation (restructuring) has occurred ("Active" in Figure 2-12). Power sector restructuring is more or less at a standstill; by 2010 there were no active proposals under review by the Federal Energy Regulatory Commission (FERC) for actions aimed at wider restructuring, and no additional states have begun retail deregulation activity since that time.

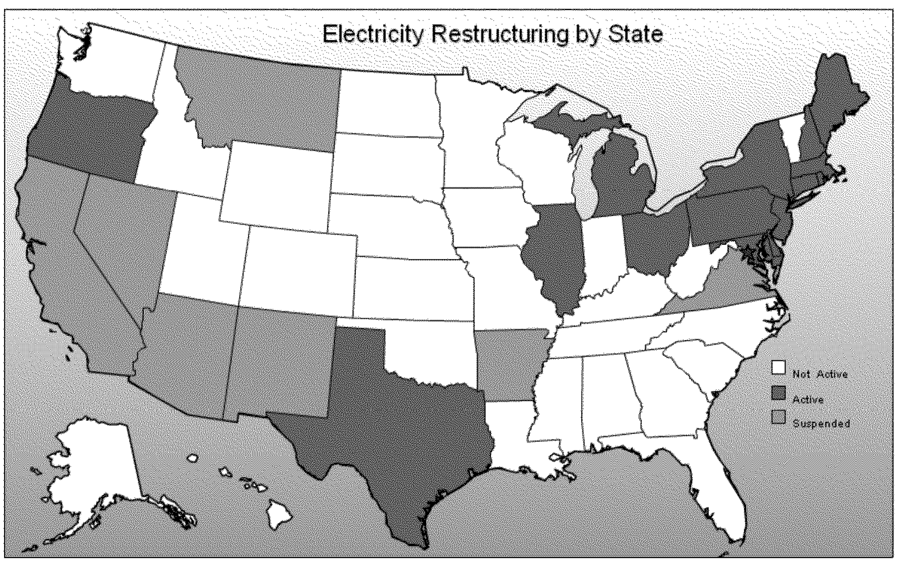


Figure 2-12. Status of State Electricity Industry Restructuring Activities
Source: EIA 2010. "Status of Electricity Restructuring by State." Available online at: http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

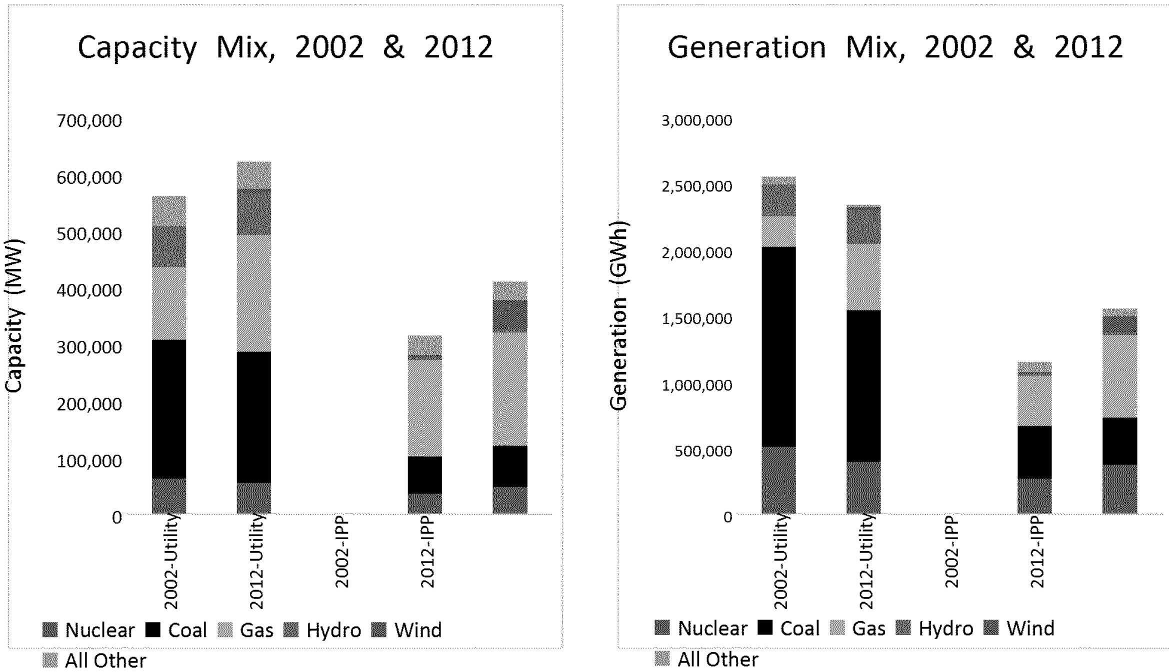
One major effect of the restructuring and deregulation of the power sector was a significant change in type of ownership of electricity generating units in the states that deregulated prices. Throughout most of the 20th century, electricity was supplied by vertically integrated regulated utilities. The traditional integrated utilities controlled generation, transmission, and distribution in their designated areas, and prices were set by cost of service regulations set by state government agencies (e.g., Public Utility Commissions). Deregulation and restructuring resulted in unbundling of the vertical integration structure. Transmission and distribution continued to operate as monopolies with cost of service regulation, while generation shifted to a mix of ownership affiliates of traditional utility ownership and some generation owned and operated by competitive companies known as Independent Power Producers (IPP). The resulting generating sector differed by state or region, as the power sector adapted to the restructuring and deregulation requirements in each state.

By 2002, the major impacts of adapting to changes brought about by deregulation and restructuring during the 1990s were largely in place. The resulting ownership mix of generating capacity (MW) in 2002 was 62 percent of the generating capacity owned by traditional utilities, 35 percent owned by IPPs,[19] and 3 percent owned by commercial and industrial producers. The mix of electricity generated (MWh) was more heavily weighted towards the utilities, with a distribution in 2002 of 66 percent, 30 percent, and 4 percent for utilities, IPPs and commercial/industrial, respectively.

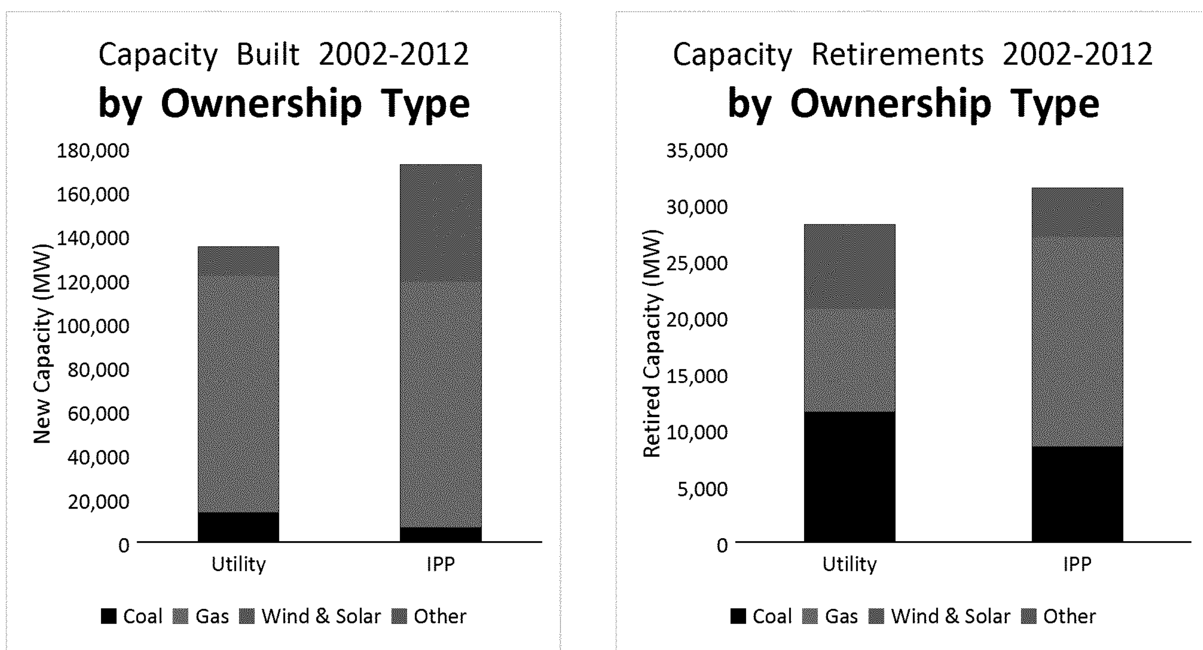
Since 2002 IPPs have expanded faster than traditional utilities, substantially increasing their share by 2012 of both capacity (58 percent utility, 39 percent IPPs, and 3 percent commercial/industrial) and generation (58 percent, 38 percent, and 4 percent).

The mix of capacity and generation in 2002 and 2012 for each of the ownership types is shown in Figures 2-13 (capacity) and 2-14 (generation). The capacity and generation data for commercial and industrial owners are not shown on these figures due to the small magnitude of those ownership types. A portion of the shift of capacity and generation is due to sales and transfers of generation assets from traditional utilities to IPPs, rather than strictly the result of newly built units.

[19] IPP data presented in this section include both combined and non-combined heat and power plants.



Figures 2-113 & 2-14. Capacity and Generation Mix by Ownership Type, 2002 & 2012



Figures 2-15 and 2-16. Generation Capacity Built and Retired between 2002 and 2012 by Ownership Type

The mix of capacity by fuel types that have been built and retired between 2002 and

2012 also varies significantly by type of ownership. Figure 2-15 presents the new capacity built during that period, showing that IPPs built the majority of both new wind and solar generating capacity, as well as somewhat more natural gas capacity than the traditional utilities built. Figure 2-16 presents comparable data for the retired capacity, showing that utilities retired more coal and "other" capacity (mostly oil-fired) than IPPs retired, while the IPPs retired more natural gas capacity than the utilities retired. The retired gas capacity was primarily (60 percent) steam and combustion turbines.

2.5 Emissions of Greenhouse Gases from Electric Utilities

The burning of fossil fuels, which generates about 69 percent of our electricity nationwide, results in emissions of greenhouse gases. The power sector is a major contributor of CO_2 in particular, but also contributes to emissions of sulfur hexafluoride (SF_6), methane (CH_4), and nitrous oxide (N_2O). In 2013, the electricity generation accounted for 38 percent of national CO_2 emissions. Including both generation and transmission (a source of SF_6), the power sector accounted for 31 percent of total nationwide greenhouse gas emissions, measured in CO_2 equivalent. Table 2-5 and Figure 2-17 show the GHG emissions[20] from the power sector relative to other major economic sectors. Table 2-6 shows the contributions of CO_2 and other GHGs from the power sector and other major emitting economic sectors.

[20] CO_2 equivalent data in this section are calculated with the IPCC SAR (Second Assessment Report) GWP potential factors.

Table 2-5. Domestic Emissions of Greenhouse Gases, by Economic Sector (million tons of CO_2 equivalent)

	2002		2013		Change Between '02 and '13		
Sector/Source	GHG Emissions	% Total GHG Emissions	GHG Emissions	% Total GHG Emissions	Change in Emissions	% Change in Emissions	% of Total Change in Emissions
Electric Power Industry	2,550	33%	2,289	31%	-260	-10%	64%
Transportation	2,158	28%	1,991	27%	-167	-8%	41%
Industry	1,564	20%	1,535	21%	-29	-2%	7%
Agriculture	618	8%	647	9%	29	5%	-7%
Commercial	402	5%	442	6%	40	10%	-10%
Residential	412	5%	413	6%	1	0%	0%
U.S. Territories	58	<1%	38	<1%	-19	-33%	5%
Total GHG Emissions	7,762	100%	7,356	100%	-406	-5%	100%
Sinks and Reductions	-976		-972		4	0%	
Net GHG Emissions	6,786		6,384		-402	-6%	

Source: EPA, 2015 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013", Table 2-12. Includes CO_2, CH_4, N_2O and SF_6 emissions.

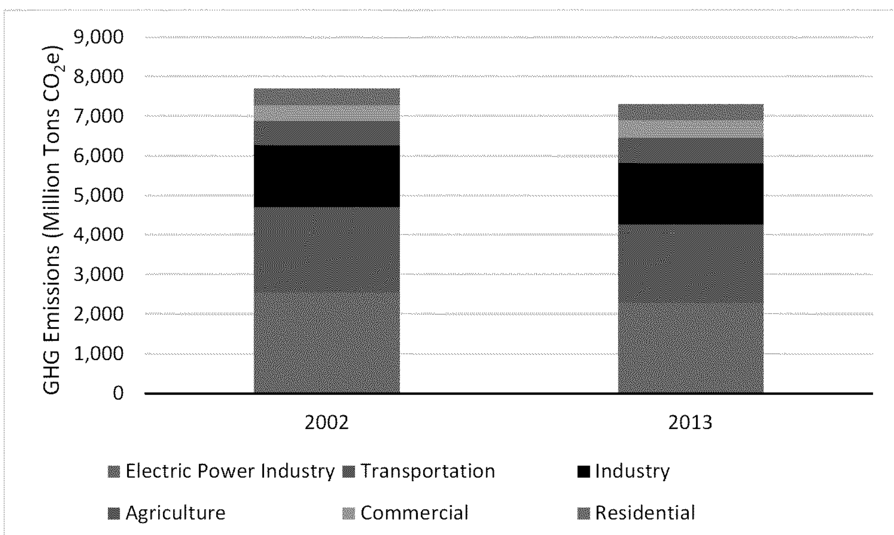


Figure 2-17. Domestic Emissions of Greenhouse Gases from Major Sectors, 2002 and 2013 (million tons of CO_2 equivalent)

Source: EPA, 2015 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013", Table 2-12

Not Shown: CO_2e emissions from U.S. Territories. The amount of CO_2 emitted during the combustion of fossil fuels varies according to the carbon content and heating value of the fuel used. The CO_2 emission factors used in IPM v5.14 (same as used in v5.13) are shown in Table 2-7. Coal has higher carbon content than oil or natural gas, and thus releases more CO_2 during combustion. Coal emits about 1.7 times as much carbon per unit of energy when burned as natural gas does (EPA 2013).

Table 2-6. Greenhouse Gas Emissions from the Electricity Sector (Generation, Transmission and Distribution), 2002 and 2013 (million tons of CO_2 equivalent)

		2002		2013		Change Between '02 and '13	
Gas/Fuel Type or Source		GHG Emissions	% of Total GHG Emissions from Power Sector	GHG Emissions	% of Total GHG Emissions from Power Sector	Change in GHG Emissions	% Change in Emissions
CO_2		2,521	98.9%	2,262	98.8%	-259	-10%
	Fossil Fuel Combustion	2,505	98.2%	2,248	98.2%	-257	-10%
	Coal	2,083	81.7%	1,736	75.8%	-347	-17%
	Natural Gas	337	13.22%	487	21.28%	150	45%
	Petroleum	84.7	3.32%	24.7	1.08%	-60.0	-71%
	Geothermal	0.4	0.02%	0.4	0.02%	0.0	0%
	Incineration of Waste	13.0	0.51%	11.1	0.49%	-1.9	-14%
	Other Process Uses of Carbonates	2.9	0.11%	2.4	0.11%	-0.4	-15%
CH_4		0.4	0.02%	0.4	0.02%	0.0	0%
	Stationary Combustion*	0.4	0.02%	0.4	0.02%	0.0	0%
	Incineration of Waste	+		+			
N_2O		13.7	0.54%	21.4	0.93%	7.7	56%
	Stationary Combustion*	13.2	0.52%	21.1	0.92%	7.8	59%
	Incineration of Waste	0.4	0.02%	0.3	0.01%	-0.1	-25%
SF_6		14.7	0.57%	5.6	0.25%	-9.0	-62%
	Electrical Transmission and Distribution	14.7	0.57%	5.6	0.25%	-9.0	-62%
Total GHG Emissions		2,550		2,289		-260	

Source: EPA, 2015 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013", Table 2-11

* Includes only stationary combustion emissions related to the generation of electricity.

** SF_6 is not covered by this rule, which specifically regulates CO_2 emissions from combustion.

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

Table 2-7. Fossil Fuel Emission Factors in the EPA Base Case 5.14 IPM Power Sector Modeling Application

Fuel Type	Carbon Dioxide (lb/MMBtu)
Coal	
Bituminous	202.8 – 209.6
Subbituminous	209.2 – 215.8
Lignite	212.6 – 219.
Natural Gas	117.1
Fuel Oil	
Distillate	161.4
Residual	161.4 – 173.9
Biomass	195
Waste Fuels	
Waste Coal	204.7
Petroleum Coke	225.1
Fossil Waste	321.1
Non-Fossil Waste	0
Tires	189.5
Municipal Solid Waste	91.9

Source: Documentation for IPM Base Case v.5.13, Table 11-5. The emission factors used in Base Case 5.14 are identical to the emission factors in IPM Base Case 5.13.

Note: CO_2 emissions presented here for biomass account for combustion only and do not reflect emissions from initial photosynthesis (carbon sink) or harvesting activities and transportation (carbon source).

2.6 Carbon Dioxide Control Technologies

In the power sector, current approaches available for significantly reducing the CO_2 emissions of new fossil fuel combustion sources to meet a 1,400 lb CO_2/MWh emission rate include the use of: (1) highly efficient coal-fired designs (e.g., modern supercritical or ultra-supercritical steam units) with up to 40 percent natural gas co-firing, (2), integrated coal gasification combined cycle (IGCC) co-firing with up to 10 percent natural gas, (3) natural gas combined cycle (NGCC) combustion turbine/steam-turbine units, and/or (4) conventional coal-fired generation with carbon capture and storage (CCS).

Investment decisions for the optimal choice of the type of new generating capacity capable of meeting the 1,400 lb CO_2/MWh standard of performance depend in part on the intended primary use of new generating capacity. Daily peak electricity demands, involving operation for relatively few hours per year, are often most economically met by simple-cycle combustion turbines (CT). Stationary CTs used for power generation can be installed quickly, at relatively low capital cost. They can be remotely started and loaded quickly, and can follow rapid demand changes. Full-load efficiencies of large current technology CTs are typically 30-33 percent but can be has high as 40 percent or more (high heating value basis), as compared to efficiencies of 50 percent or more for new combined-cycle units that recover and use the exhaust heat otherwise wasted from a CT. A simple-cycle CT's lower efficiency causes it to burn much more fuel to produce a MWh of electricity than a combined-cycle unit. Thus, when burning natural gas its CO_2 emission rate per MWh could be 40-60 percent higher than a more efficient NGCC unit.

Base load electricity demand can be met with NGCC generation, coal and other fossil-fired steam generation, and IGCC technology, as well as generation from sources that do not emit CO_2, such as nuclear and hydro. IGCC employs the use of a gasifier to transform fossil fuels into synthesis gas ("syngas") and heat. The syngas is used to fuel a combined cycle generator, and the heat from the syngas conversion can produce steam for the steam turbine portion of the combined cycle generator. Electricity can be generated through this IGCC process somewhat more efficiently than through conventional boiler-steam generators. Additionally, with gasification, some of the syngas can be converted into other marketable products such as fertilizers and chemical feedstocks for processes to manufacture liquid hydrocarbons (e.g., fuels and lubricants), and CO_2 can be captured for use in EOR. Figure 2-18 shows the array of products (including electricity) and by-products that can be produced in a syngas process.

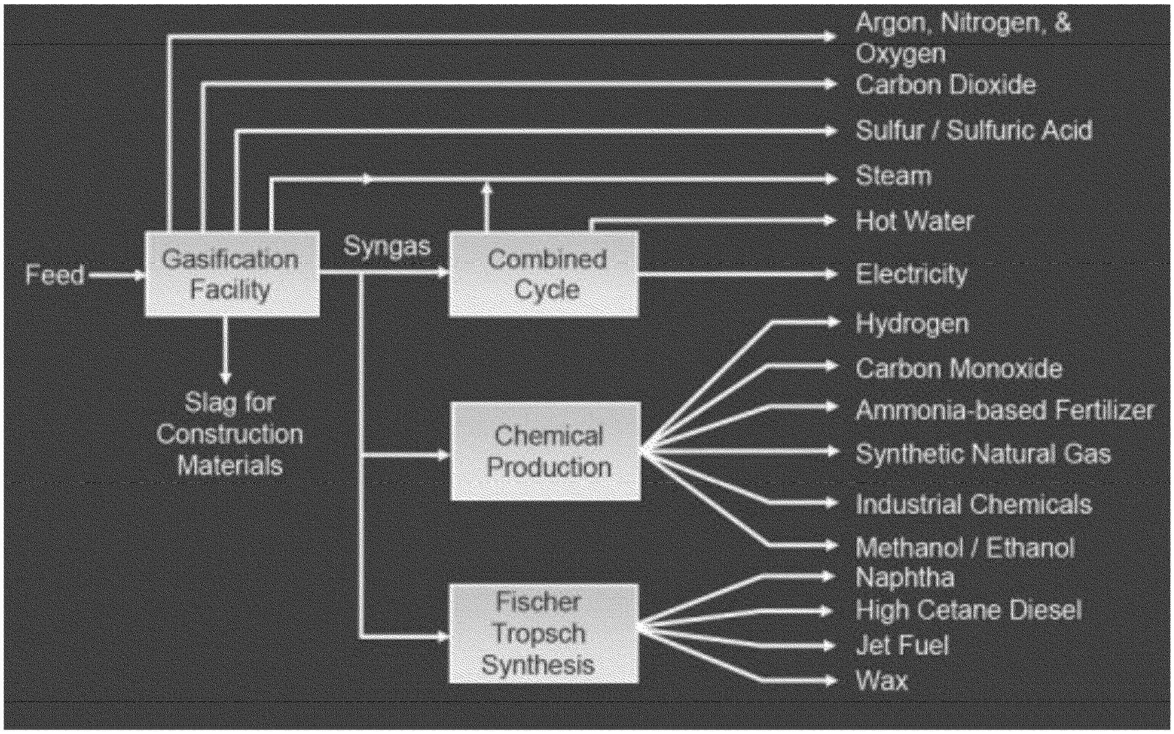


Figure 2-18. Marketable products from Syngas Generation

Source: National Energy Technology Lab. Gasifipedia. Available at http://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/co-generation

2.6.1 Carbon Capture and Storage

CCS can be achieved through either pre-combustion or post-combustion capture of CO_2 from a gas stream associated with the fuel combusted. Furthermore, CCS can be designed and operated for full capture of the CO_2 in the gas stream (i.e., above 90 percent) or for partial capture (below 90 percent). Post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system – such as a utility boiler. It is referred to as “post-combustion capture” because the CO_2 is the product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. This process is illustrated for a pulverized coal power plant in Figure 2-19 and described in more detail in the preamble. (See preamble section V.D.) For post-combustion, a station's net generating output will be lower due to the energy needs of the capture process.

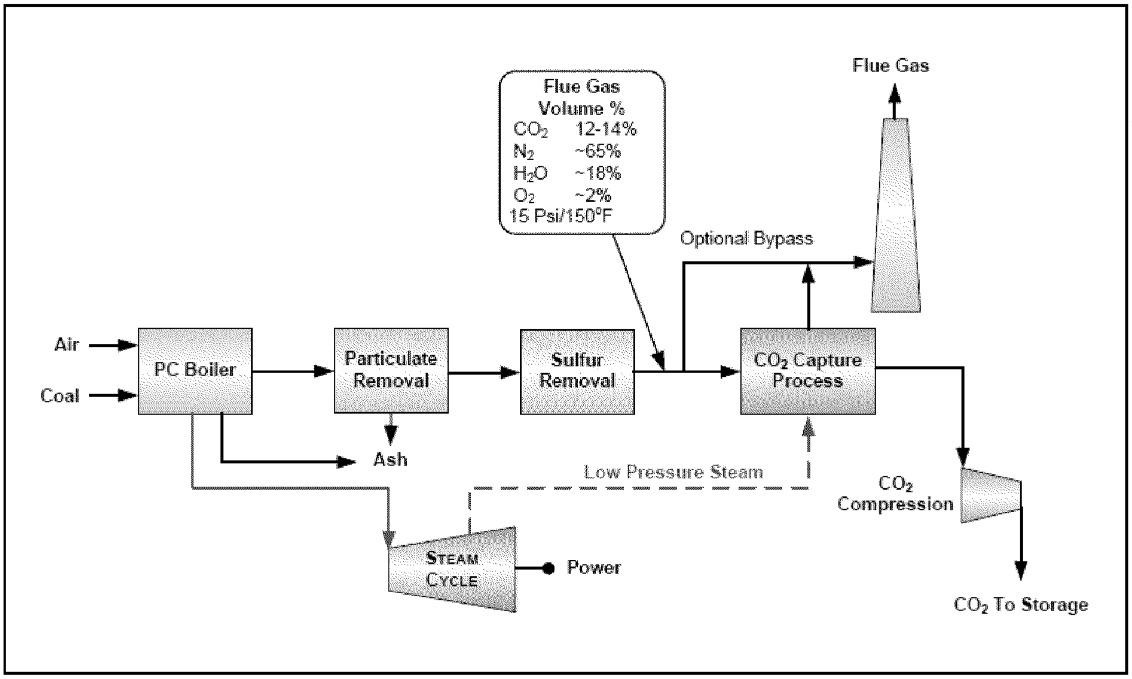


Figure 2-19. Post-Combustion CO_2 Capture for a Pulverized Coal Power Plant

Source: Interagency Task Force on Carbon Capture and Storage 2010

Pre-combustion capture is mainly applicable to IGCC facilities, where the fuel is converted into syngas under heat and pressure and some percentage of the carbon contained in the syngas is captured before combustion.[21] For pre-combustion technology, a significant amount of energy is needed to gasify the fuel(s). This process is illustrated in Figure 2-20. Application of post-combustion CCS with IGCC can be designed to use no water-gas shift, or single- or two-stage shift processes, to obtain varying percentages of CO_2 removal – from a "partial capture" percentage to 90 percent "full capture." Pre-combustion CCS typically has a lesser impact on net energy output than does post-combustion CCS. For more detail on CCS technology, see the "Report of the Interagency Task Force on Carbon Capture and Storage" (2010).[22]

[21] Note that pre-combustion CCS is not considered the best system of emission reduction for this standard. This information is provided for background purposes.

[22] For more information on the cost and performance of CCS, see http://www.netl.doe.gov/energy-analyses/baseline_studies.html.

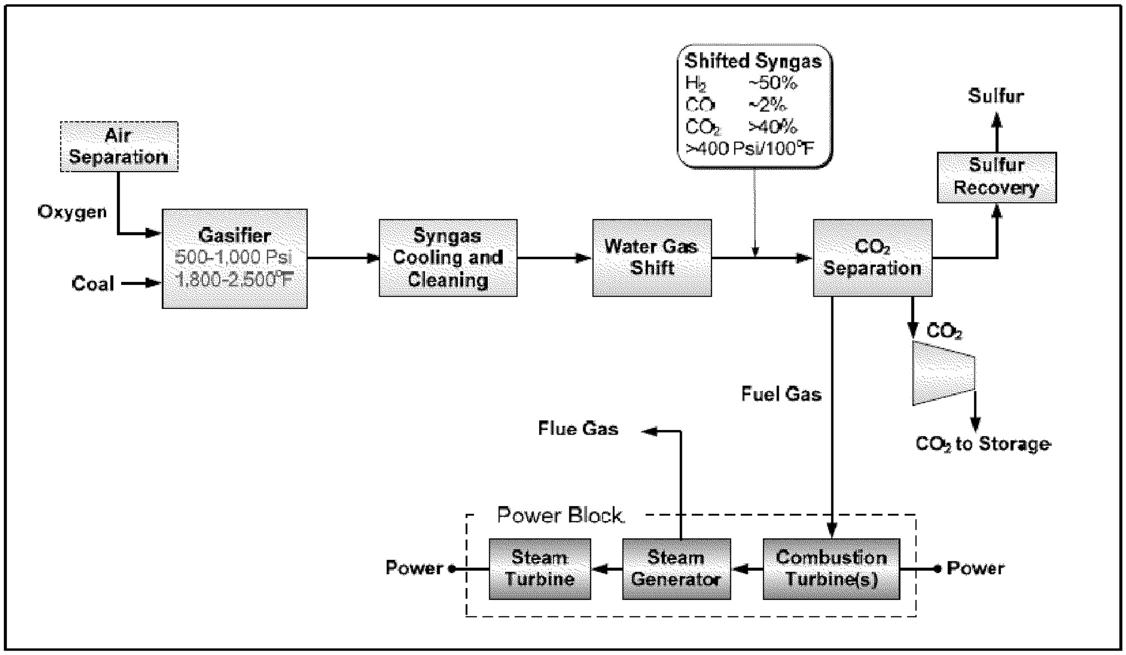


Figure 2-20. Pre-Combustion CO_2 Capture for an IGCC Power Plant
Source: Interagency Task Force on Carbon Capture and Storage 2010

Carbon capture technology has been successfully applied since 1930 on several smaller scale industrial facilities and more recently in a number of demonstration phase projects worldwide for power sector applications. In October 2014, the first commercial-scale coal-fired capture and storage project for electricity generation began operation at the Boundary Dam Power Station in Saskatchewan, Canada. The Boundary Dam Station is owned by the Province of Saskatchewan, and operated by SaskPower, a provincially owned corporation that is the primary electric utility in the Province. The commercial-scale demonstration project retrofit Unit 3 (a 130 MW, coal fired built in 1970, and rebuilt in 2013) at a total cost of approximately $1.5 billion (Canadian, or about $1.2 billion U.S.), including a partial subsidy of $240 million (Canadian) by the Canadian federal government. The carbon capture system is a post-combustion process designed to capture 90 percent of the CO_2 emitted by Unit #3. Retrofitting the carbon capture system reduced the capacity of the unit to 110 MW. The majority of the captured CO_2 is used for an enhanced oil recovery (EOR) project in southern Saskatchewan. The portion of the CO_2 is being stored in a nearby research and monitoring geological storage facility, where the captured CO_2 will be injected 3.4 kilometers underground into a sandstone formation located below the major coal field supplying lignite to Unit # 3. The remaining captured CO_2 will be injected into deep saline formations.

In the United States there are two commercial-scale CCS facilities nearing completion:

1) the Kemper County Carbon Dioxide Capture and Storage Project in Mississippi, and

2) The W.A. Parish Petra Nova CCA Project near Houston, Texas.

Construction began on the Kemper project in 2010, and the startup is currently scheduled for May 2016. The Kemper project is constructing a new 524 MW lignite unit as well as a 58 MW natural gas unit. Mississippi Power (a division of Southern Power) is building and will operate the Kemper project. The control system is designed to capture 65 percent of the CO_2 generated by the plant, and is projected to capture 3.5 million tons of CO_2 per year. The resulting CO_2 emission rate is expected to be ~800 pounds per MWh produced. The current total cost estimate is $5.6 billion, a substantial increase from the original $2.4 billion estimate.[23] The construction has received a $270 million grant from the U.S. Department of Energy, and $133 million in investment tax credits from the Internal Revenue Service. The captured CO_2 will be transported via a 60 mile pipeline and used for EOR projects in mature Mississippi oil fields.[24]

The only other commercial-scale electricity power sector CCS project currently under construction in the United States is the W.A. Parish Petra Nova CCS Project near Houston, Texas. The Parish Petra project is a 50/50 partnership between NRG Energy (an integrated electricity company generating and supplying electricity to 1.6 million customers in Texas) and the Nippon Oil and Gas Exploration Company. The Parish project will retrofit a post-combustion CCS system on a portion of the flue gas from the existing 610 MW coal fired Unit # 8. The CCS system will treat a 240 MW slipstream of the flue gas, and is designed to capture 90 percent of the CO_2 in the treated flue gas. The capacity rating of Unit # 8 will not be reduced due to the CCS project because an 85 MW custom-built natural gas fired combustion turbine co-generation unit is being built on-site to provide both electricity and steam to the CCS unit. The total cost of the CCS project is estimated to be $1 billion (including a $167 million grant from the U.S. Department of Energy), and the project is expected to extract 1.4 – 1.6 million tons of CO_2 per year. The construction contract was awarded in July, 2014, and operation is expected to begin in early 2016. The CO_2 will be piped 85 miles to a reservoir for EOR in the West Ranch Oil

[23] The Mississippi Public Utilities Staff authorized an independent monitor to conduct a review of the project. The findings of the review are provided in a summary report available at: http://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=328417

[24] Carbon Capture and Sequestration Technologies Program at MIT. Accessed 1/23/2015. https://sequestration.mit.edu/tools/projects/kemper.html

Field.[25]

2.7 Geologic and Geographic Considerations for Geologic Sequestration

Geologic sequestration (GS) (i.e., long-term containment of a CO_2 stream in subsurface geologic formations) is technically feasible and available throughout most of the United States. (See generally preamble to final rule at sections V.M and N.) GS is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO_2 increases oil production efficiency through EOR. CO_2 may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs, such as unmineable coal seams, also offer the potential for GS. The geographic availability of deep saline formations, EOR, and unmineable coal seams is shown in Figure 2-21. Estimates of CO_2 storage resources by state compiled by the Department of Energy's (DOE) National Carbon Sequestration Database and Geographic Information System (NATCARB) and published in DOE's 2012 United States Carbon Utilization and Storage Atlas (discussed below) are provided in Table 2-8.

[25] U.S. DOE (2010) "Recovery Act: W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project". http://www.netl.doe.gov/research/proj?k=FE0003311 Accessed 1/23/2015

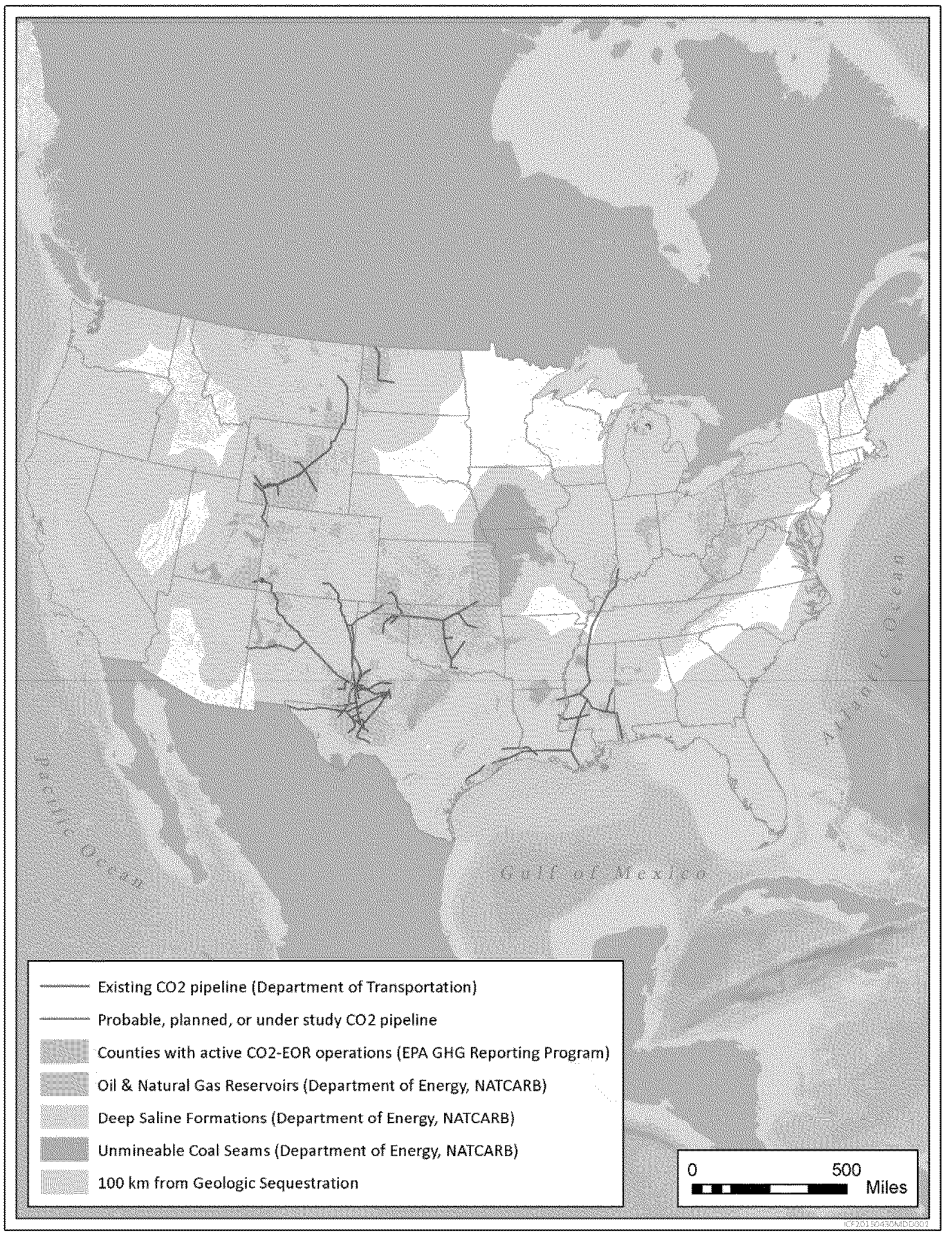


Figure 2-21 Geologic Sequestration in the Continental United States

Sources: EPA Greenhouse Gas Reporting Program; Department of Energy, NATCARB; Department of Transportation, National Pipeline Management System.

Table 2-8. Total CO_2 Storage Resource (U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL))[26]

	Million Tons	
State	**Low Estimate**	**High Estimate**
ALABAMA	135,022	765,422
ALASKA	9,524	21,771
ARIZONA	143	1,290
ARKANSAS	6,812	70,184
CALIFORNIA	37,357	463,665
COLORADO	41,458	393,734
CONNECTICUT	not assessed by DOE-NETL	not assessed by DOE-NETL
DELAWARE	44	44
DISTRICT OF COLUMBIA	not assessed by DOE-NETL	not assessed by DOE-NETL
FLORIDA	113,251	611,793
GEORGIA	160,210	175,322
HAWAII	not assessed by DOE-NETL	not assessed by DOE-NETL
IDAHO	44	430
ILLINOIS	11,045	128,772
INDIANA	35,296	75,189
IOWA	11	55
KANSAS	11,993	95,173
KENTUCKY	3,219	8,433
LOUISIANA	186,842	2,319,238
MAINE	not assessed by DOE-NETL	not assessed by DOE-NETL
MARYLAND	2,050	2,127
MASSACHUSETTS	not assessed by DOE-NETL	not assessed by DOE-NETL

(Continued on next page)

[26] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

Table 2-8. Total CO_2 Storage Resource (DOE-NETL), cont.

	Million Tons*	
State	**Low Estimate**	**High Estimate**
MICHIGAN	20,999	52,040
MINNESOTA	not assessed by DOE-NETL	not assessed by DOE-NETL
MISSISSIPPI	159,846	1,306,270
MISSOURI	11	187
MONTANA	93,233	1,006,100
NEBRASKA	26,202	124,826
NEVADA	not assessed by DOE-NETL	not assessed by DOE-NETL
NEW HAMPSHIRE	not assessed by DOE-NETL	not assessed by DOE-NETL
NEW JERSEY	0	0
NEW MEXICO	47,135	395,828
NEW YORK	5,115	5,115
NORTH CAROLINA	1,477	20,271
NORTH DAKOTA	73,954	162,569
Offshore Federal Only	539,956	7,098,976
OHIO	14,837	14,837
OKLAHOMA	62,777	269,570
OREGON	7,507	103,286
PENNSYLVANIA	24,361	24,361
RHODE ISLAND	not assessed by DOE-NETL	not assessed by DOE-NETL
SOUTH CAROLINA	33,180	37,677
SOUTH DAKOTA	9,656	26,489
TENNESSEE	474	4,255
TEXAS	489,205	4,772,925
UTAH	28,076	265,558
VERMONT	not assessed by DOE-NETL	not assessed by DOE-NETL
VIRGINIA	485	3,208
WASHINGTON	40,367	547,550
WEST VIRGINIA	18,353	18,353
WISCONSIN	not assessed by DOE-NETL	not assessed by DOE-NETL
WYOMING	80,127	754,917
U.S. Total	**2,531,653**	**22,147,811**

* States with a "zero" value represent estimates of minimal CO_2 storage resource. States that have not yet been assessed by DOE-NETL have been identified.

2.7.2 Availability of Geologic Sequestration in Deep Saline Formations

DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration capacity of deep saline formations in the United States. DOE estimates are compiled by the DOE's NATCARB system using volumetric models and published in a Carbon Utilization and Storage Atlas.[27] DOE estimates that areas of the United States with appropriate geology have a sequestration potential of at least 2,200 billion tons of CO_2 in deep saline formations. According to DOE, at least 39 states have geologic characteristics that are amenable to deep saline GS in either onshore or offshore locations. In 2013, the USGS completed its evaluation of the technically accessible GS resources for CO_2 in U.S. onshore areas and state waters using probabilistic assessment.[28] The USGS estimates a mean of 3,300 billion tons of subsurface CO_2 sequestration potential, including saline and oil and gas reservoirs, across the basins studied in the United States. As shown in Figure 2-21, there are 39 states for which onshore and offshore deep saline formation storage capacity has been identified.[29]

2.7.3 Availability of CO_2 Storage via Enhanced Oil Recovery

Although the regulatory impact analysis for this rule relies on GS in deep saline formations, the EPA also recognizes the potential for securely sequestering CO_2 via EOR. EOR has been successfully used at numerous production fields throughout the United States to increase oil recovery. The oil industry in the United States has over 40 years of experience with EOR. An oil industry study in 2014 identified more than 125 EOR projects in 98 fields in the United States.[30] More than half of the projects evaluated in the study have been in operation for more than 10 years, and many have been in operation for more than 30 years. This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure GS that can be used for deployment of CCS across geographically diverse areas.

Currently, 12 states have active EOR operations and most have developed an extensive CO_2 infrastructure, including pipelines, to support the continued operation and growth of EOR.

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[27] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

[28] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, p. 41, http://pubs.usgs.gov/circ/1386/.

[29] Alaska is not shown in the figure; it has deep saline formation storage capacity, geology amenable to EOR operations, and potential GS capacity in unmineable coal.

[30] Koottungal, Leena, 2014, 2014 Worldwide EOR Survey, Oil & Gas Journal, Volume 112, Issue 4, April 7, 2014 (corrected tables appear in Volume 112, Issue 5, May 5, 2014).

An additional 18 states are within 100 kilometers (62 miles) of current EOR operations (see Figure 2-21).[31] The vast majority of EOR is conducted in oil reservoirs in the Permian Basin, which extends through southwest Texas and southeast New Mexico. States where EOR is currently used include Alabama, Colorado, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, Utah, and Wyoming.

At the project level, the volume of CO_2 already injected for EOR and the duration of operations are of similar magnitude to the duration and volume of CO_2 expected to be captured from fossil fuel-fired EGUs. The volume of CO_2 used in EOR operations can be large (e.g., 55 million tons of CO_2 were stored in the SACROC unit in the Permian Basin over 35 years), and operations at a single oil field may last for decades, injecting into multiple parts of the field.[32] According to data reported to the EPA's Greenhouse Gas Reporting Program (GHGRP), approximately 66 million tons of CO_2 were supplied to EOR in the United States in 2013.[33] Approximately 70 percent of this total CO_2 supplied was produced from natural (geologic) CO_2 sources, and approximately 30 percent was captured from anthropogenic sources.[34]

A DOE-sponsored study has analyzed the geographic availability of applying EOR in 11 major oil producing regions of the United States and found that there is an opportunity to significantly increase the application of EOR to areas outside of current operations.[35] DOE-sponsored geologic and engineering analyses show that expanding EOR operations into areas additional to the capacity already identified and applying new methods and techniques over the next 20 years could utilize 20 billion tons of anthropogenic CO_2 and increase total oil production by 67 billion barrels. The availability of anthropogenic CO_2 in areas outside of current sources could drive new EOR projects by making more CO_2 locally available.

2.8 State Policies on GHG and Clean Energy Regulation in the Power Sector

Several states have also established emission performance standards or other measures to limit emissions of GHGs from new EGUs that are comparable to or more stringent than this rulemaking.

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[31] The distance of 100 kilometers reflects the assumptions in the DOE-NETL cost estimates.

[32] Han, Weon S., McPherson, B J., Lichtner, P C., and Wang, F P. "Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection." American Journal of Science 310. (2010): 282-324.

[33] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[34] Ibid.

[35] "Improving Domestic Energy Security and Lowering CO_2 Emissions with 'Next Generation' CO_2-Enhanced Oil Recovery", Advanced Resources International, Inc. (ARI), 2011. Available at: http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=df02ffba-6b4b-4721-a7b4-04a505a19185.

In 2003, then-Governor George Pataki sent a letter to his counterparts in the Northeast and Mid-Atlantic inviting them to participate in the development of a regional cap-and-trade program addressing power plant CO_2 emissions. This program, known as the Regional Greenhouse Gas Initiative (RGGI), began in 2009 and sets a regional CO_2 cap for participating states. The currently participating states include: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The cap covers CO_2 emissions from all fossil-fired EGUs greater than 25 MW in participating states, and limits total emissions to 91 million tons in 2014. The 2014 emissions cap is a 51 percent reduction below the initial cap in 2009 to 2011 of 188 million tons. This emissions budget is reduced 2.5 percent annually from 2015 to 2020. RGGI CO_2 allowances are sold in a quarterly auction. RGGI conducted their 27th quarterly allowance auction in March, 2015 the market clearing price was \$5.41 per ton of CO_2 for current allowances, which was a record high price (the February '15 price of \$5.21 was the previous record). A total of allowances for 15.3 million tons were sold in the March 2015 auction, well below the record of 38.7 million tons sold in June 2013 for \$3.21 per ton.

In September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO_2/MWh -net.

In 2006, Governor Schwarzenegger also signed into law Assembly Bill 32, the Global Warming Solutions Act of 2006. This act includes a multi-sector GHG cap-and-trade program which covers approximately 85 percent of the state GHG emissions. EGUs are included in phase I of the program, which began in 2013. Phase II begins in 2020 and includes upstream sources. The cap is based on a 2 percent reduction from total 2012 expected emissions, and declines 2 percent annually through 2014, then 3 percent each year until 2020. The AB32 cap and trade program began functioning in 2011, and functioning market is now operating on the NYMEX futures commodity market. The final 2014 market price for carbon allowances was \$11.23/ton of carbon. On April 17, 2015 the 2015 allowance futures price was \$11.48/ton, and the spot price was \$11.30/ton.

In May 2007, Washington Governor Gregoire signed Substitute Senate Bill 6001, "Baseload Electric Generation Performance" which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any baseload electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Baseload generation facilities must initially comply with an emission limit of 1,100 lb CO_2/MWh-net. In 2013 the State of Washington revised[36] the emission limit to 970 lb CO_2/MWh-net based on a survey of available NGCC generation units commercially available in the United States.

In 1997, Oregon required a new baseload gas fired power plants to meet a CO_2 emission standard that was 17 percent below the most efficient NGCC unit operating in the United States. In 2000 Oregon established that the effective 17 percent below most efficient was 675 lb CO_2/MWh-net In July 2009, Oregon Governor Kulongoski signed Senate Bill 101, which mandated that facilities generating baseload electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO_2/MWh-net regardless of fuel type, and prohibited utilities from entering into long-term purchase agreements for baseload electricity with out-of-state facilities that do not meet that standard. Natural gas- and petroleum distillate-fired facilities that are primarily used to serve peak demand or to integrate energy from renewable resources are specifically exempted from the performance standard.

In August 2011, New York Governor Cuomo signed the Power NY Act of 2011. Implementing regulations established CO_2 emission standards for new and modified electric generators greater than 25 MW. The standards vary based on the type of facility: base load facilities must meet a CO_2 standard of 925 lb/MWh-net or 120 lb/MMBtu, and peaking facilities must meet a CO_2 standard of 1,450 lb/MWh-net or 160 lb/MMBtu-net.

Several other states have enacted CO_2 regulations affecting EGUs that do not set emission limits, but set other regulatory requirements limiting CO_2 emissions from EGUs. For example, Montana enacted a law in 2007 requiring the Public Service Commission to limit approvals of new equity interests in or leases of a facility used to generate coal-based electricity to facilities that capture and sequester at least half of their CO_2 emissions. Minnesota enacted the Next Generation Energy Act in 2007 requiring increases in power sector greenhouse gas emissions from any new large coal energy facilities built in Minnesota or the import of electricity from such a facility located out of state to be offset by equivalent emission reductions. New Mexico enacted legislation in 2007 authorizing tax credits and cost recovery incentives for qualifying coal-fired facilities. To qualify, plants must capture and store emissions so that they emit less than 1,100 lb CO_2/MWh, among other requirements.

[36] Washington Department of Commerce, 2013. "Greenhouse Gas Emission Performance Standard for Baseload Electric Generation." Available at http://www.commerce.wa.gov/Documents/Concise-Expl-Stmt-WSR-13-06-074.pdf.

Additionally, most states have implemented Renewable Portfolio Standards (RPS), or Renewable Electricity Standards (RES). These programs are designed to increase the renewable share of a state's total electricity generation. Currently 29 states, the District of Columbia and Guam have enforceable RPS or other mandatory renewable capacity policies, and 8 states, Puerto Rico and Guam have voluntary goals.[37] These programs vary widely in structure, enforcement, and scope.

2.9 Revenues and Expenses

Due to lower retail electricity sales, total utility operating revenues declined in 2012 to $271 billion from a peak of almost $300 billion in 2008. Despite revenues not returning to 2008 levels in 2012, operating expenses were appreciably lower and as a result, net income also rose in comparison to 2008 (see Table 2-9). Recent economic events have put downward pressure on electricity demand, thus dampening electricity prices and consumption (utility revenues), but have also reduced the price and cost of fossil fuels and other expenses. In 2012 electricity generation was 1.28 percent below the generation in 2011, and has declined in four of the past five years.

Table 2-9 shows that investor-owned utilities (IOUs) earned income of about 13.0 percent compared to total revenues in 2012. The 2012 return on revenue was the third highest year for the period 2002 to 2012 (average: 11.9 percent, range: 10.6 percent to 13.32 percent).

Table 2-9. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities for 2002, 2008 and 2012 (nominal $millions)

	2002	2008	2012
Utility Operating Revenues	**219,609**	**298,962**	**270,912**
Electric Utility	200,360	266,124	249,166
Other Utility	19,250	32,838	21,745
Utility Operating Expenses	**189,062**	**267,263**	**235,694**
Electric Utility	171,604	236,572	220,722
Operation	116,660	175,887	152,379
Production	90,715	140,974	111,714
Cost of Fuel	24,149	47,337	38,998
Purchased Power	58,810	84,724	54,570
Other	7,776	8,937	18,146
Transmission	3,560	6,950	7,183
Distribution	3,117	3,997	4,181

[37] Clean Energy States Alliance 2013

Customer Accounts	4,168	5,286	5,086
Customer Service	1,820	3,567	5,640
Sales	264	225	221
Admin. and General	13,018	14,718	18,353
Maintenance	10,861	14,192	15,489
Depreciation	16,199	19,049	23,677
Taxes and Other	26,716	26,202	29,177
Other Utility	17,457	30,692	14,972
Net Utility Operating Income	**30,548**	**31,699**	**35,218**

Source: Table 8.3, EIA Electric Power Annual, 2012
Note: These data do not include information for public utilities, nor for IPPs.

2.10 Natural Gas Market

The natural gas market in the United States has historically experienced significant price volatility from year to year and between seasons, can undergo major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand), and has seen a dramatic shift since 2008 due to increased production from shale formations. Over the last decade, the annual average nominal price of gas delivered to the power sector peaked in 2008 at $9.02/MMBtu and has since fallen dramatically to a low of $3.42/MMBtu in 2012. During that time, the daily price[38] of natural gas reached as high as $18.48/MMBtu and as low as $2.03/MMBtu. Adjusting for inflation using the GDP implicit price deflator, in 2011 dollars the annual average price of natural gas delivered to the power sector peaked at $9.38/MMBtu in 2008 and has fallen to a low of $3.36/MMBtu in 2012. The annual natural gas prices in both nominal and real (2011$) terms are shown in Figure 2-22. A comparison of the trends in the real price of natural gas with the real prices of delivered coal and oil is shown in Figure 2-23. Figure 2-23 shows that while the real price of coal and oil increased from 2002 to 2012 (+54 percent and +203 percent respectively), the real price of natural gas declined by 22 percent in the same period. Most of the decline in real natural gas prices occurred between 2008 (the peak price year) and 2012, during which real gas prices declined by 64 percent while coal and oil prices both increased by 9 percent in the same period. The sharp decline in natural gas prices from 2008 to 2012 was primarily caused by the rapid increase in natural gas production from shale formations.

[38] Henry Hub daily prices. Henry Hub is a major gas distribution hub in Louisiana; Henry Hub prices are generally seen as the primary metric for national gas prices for all end uses. The price of natural gas delivered to electricity generation differs substantially in different regions of the country, and can be higher or lower than the Henry Hub national benchmark price.

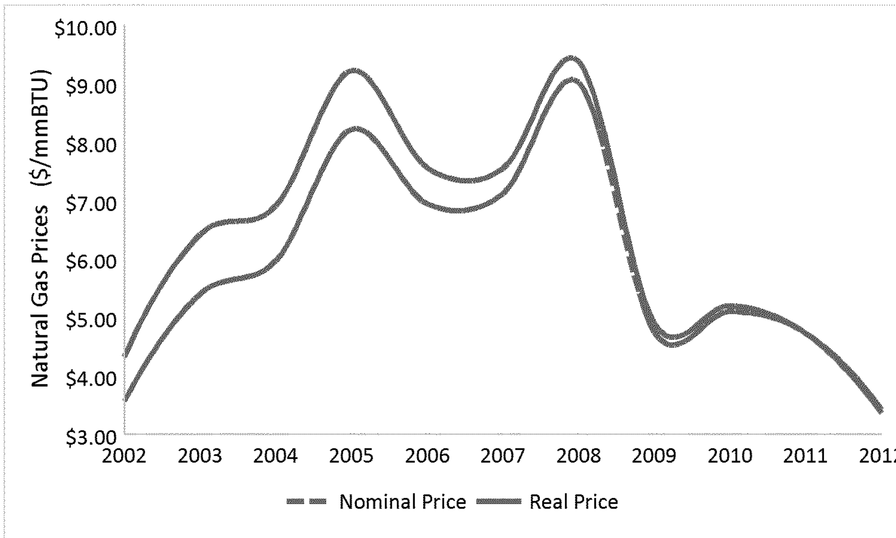

Figure 2-22. Nominal and Real (2011$) Prices of Natural Gas Delivered to the Power Sector ($/MMBtu)

Source: http://www.eia.gov/totalenergy/data/monthly/#prices. Downloaded 2/15/2015.

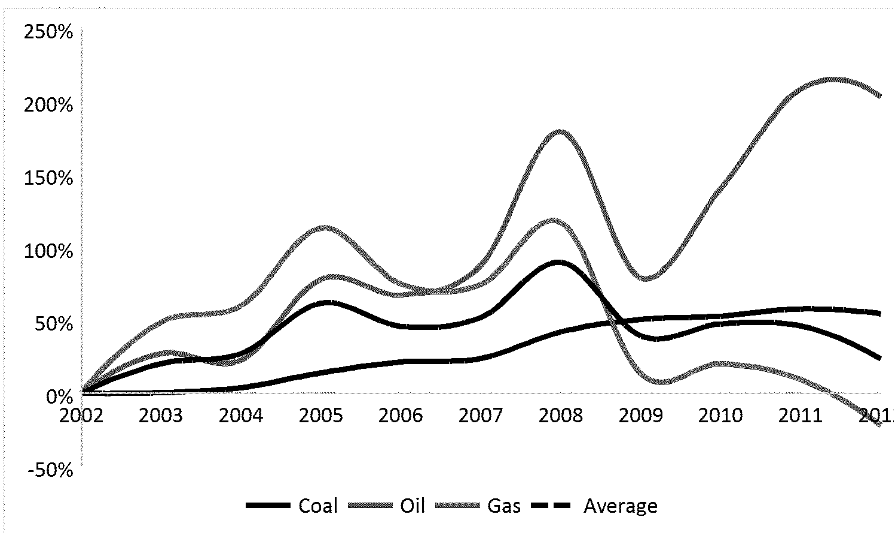

Figure 2-23. Relative Change in Real (2011$) Prices of Fossil Fuels Delivered to the Power Sector ($/MMBtu)

Source: http://www.eia.gov/totalenergy/data/monthly/#prices. Downloaded 2/15/2015.

Current and projected natural gas prices are considerably lower than the prices observed over the past decade, largely due to advances in hydraulic fracturing and horizontal drilling techniques that have opened up new shale gas resources and substantially increased the supply of economically recoverable natural gas. According to the U.S. Energy Information Administration's Annual Energy Outlook 2012 (AEO 2012) (EIA 2012):

> Shale gas refers to natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States.

The EIA's AEO 2014 estimates that the United States possessed 2,266 trillion cubic feet (Tcf) of technically recoverable dry natural gas resources as of January 1, 2012. Proven reserves make up 15 percent of the technically recoverable total estimate, with the remaining 85 percent from unproven reserves. Natural gas from proven and unproven shale resources accounts for 611 Tcf of this resource estimate.

Many shale formations, especially the Marcellus[39], are so large that only small portions of the entire formations have been intensively production-tested. Furthermore, estimates from the Marcellus and other emerging fields with few wells already drilled are likely to shift significantly over time as new geological and production information becomes available. Consequently, there is some uncertainty in estimate of technically recoverable resources, and it is regularly updated as more information is gained through drilling and production.

At the 2012 rate of U.S. consumption (about 25.6 Tcf per year), 2,266 Tcf of natural gas is enough to supply nearly 90 years of use. The AEO 2014 estimate of the shale gas resource base is modestly higher than the AEO 2012 estimate (2,214 Tcf) of shale gas production, driven by lower drilling costs and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value in energy equivalent terms than dry natural gas.[40]

EIA's projections of natural gas conditions did not change substantially in AEO 2014 from

[39] The Marcellus formation, underlying most of Pennsylvania and West Virginia, along with portions of New York and Ohio, in 2014 produced 36 precent of the U.S. total natural gas extracted from shale formations.

[40] For more information, see: http://www.eia.gov/forecasts/archive/aeo11/IF_all.cfm#prospectshale; http://www.eia.gov/energy_in_brief/about_shale_gas.cfm

either the AEO 2012 or 2013, and EIA is continues to forecast abundant reserves consistent with the above findings. Recent historical data reported to EIA is also consistent with these trends, with 2014 being the highest year on record[41] for domestic natural gas production.[42]

[41] The total dry gas production in 2012 from the lower 48 states, including both onshore and offshore production, was 23.97 Tcf, a 1.5 percent increase from 2013 and a 7.9 percent total increase from 2011

[42] http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=8-AEO2014&table=72-AEO2014&region=0-0&cases=ref2014-d102413a

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CHAPTER 3
BENEFITS OF REDUCING GREENHOUSE GAS EMISSIONS AND OTHER POLLUTANTS

This rule is designed to set emission limits for carbon dioxide (CO_2), thereby limiting potential increases in future emissions and atmospheric CO_2 concentrations. This will reduce the risk of adverse effects of climate change. As discussed in Chapter 4, the U.S. Environmental Protection Agency (EPA) anticipates negligible CO_2 emission changes resulting from the rule relative to baseline conditions, due to market baseline market conditions. The final standards provide the benefit of regulatory certainty that any new coal-fired power plant must limit its CO_2 emissions to a level reflecting the performance of a highly efficient super critical pulverized coal (SCPC) unit utilizing post-combustion partial carbon capture and storage (CCS). As explained in preamble section V.P.1.b, there are documented instances of project developers abandoning projects using CCS due to this lack of regulatory certainty. In addition, the history of regulatory actions has shown that emission standards that are based on the performance of advanced control equipment lead to increased use of that control equipment, and that the absence of a requirement stifles technology development. (See preamble section V.P.1.b.)

This chapter summarizes the adverse effects on public health and public welfare from the emissions of CO_2, which is a well-mixed greenhouse gas. This form of air pollution was determined by the EPA in the 2009 Endangerment Finding to endanger public health and welfare.[43] The major assessments by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) served as the primary scientific bases for the Endangerment Finding. A discussion of climate science findings from newer assessments can be found in the Preamble. This chapter also provides a general discussion about how the climate-related and human health benefits of emissions reductions are estimated. These valuation approaches are used in Chapter 5 to quantify and monetize the relative differences in emissions between electric generating technologies that may be constructed in the future.

3.1 Overview of Climate Change Impacts from GHG Emissions

Through the implementation of CAA regulations, the EPA addresses the negative externalities caused by air pollution. The preamble to the final rule summarizes the public

[43] Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009). See also *Coalition for Responsible Regulation v. EPA*, 684 F. 3d at 119-126, upholding the Endangerment Finding in all respects, and noting that "[t]he body of scientific evidence marshaled by EPA in support of the Endangerment Finding is substantial" (id. at 120).

health and public welfare impacts that were detailed in the 2009 Endangerment Finding. For health, these include the increased likelihood of heat waves, negative impacts on air quality, more intense hurricanes, more frequent and intense storms and heavy precipitation, and impacts on infectious and waterborne diseases. For welfare, these include reduced water supplies in some regions, increased water pollution, increased occurrences of floods and droughts, rising sea levels and damage to coastal infrastructure, increased peak electricity demand, changes in ecosystems, and impacts on indigenous communities.

The preamble also summarizes new scientific assessments and recent climatic observations. Major scientific assessments released since the 2009 Endangerment Finding have further improved scientific understanding of climate change, and provide even more evidence that GHG emissions endanger public health and welfare for current and future generations. The Third National Climate Assessment (NCA3), in particular, assessed the impacts of climate change on human health in the United States, finding that, Americans will be impacted by “increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks.” The IPCC reported similar conclusions in its Fifth Assessment Report, finding that it is likely that adverse health impacts related to heat exposure are already being exacerbated by climate change and that, if unabated, climate change will lead to a greater risk of morbidity and mortality due to more intense heat waves, undernutrition, and increased prevalence of food- and water-borne illnesses. These assessments also detail the risks to vulnerable groups such as children, the elderly and low income households. Furthermore, the assessments present an improved understanding of the impacts of climate change on public welfare, improved projections of future warming over the next century, higher projections of future sea level rise than had been previously estimated due in part to improved understanding of the Antarctic and Greenland ice sheets, more detailed description of U.S. impacts based on the National Climate Assessment, improved understanding of changes in rainfall and droughts, and new assessments of the impacts of climate change on permafrost and ocean acidification. The impacts of GHG emissions will be realized worldwide, independent upon their location of origin, and impacts outside of the United States will produce consequences relevant to the United States.

3.2 Social Cost of Carbon

The social cost of carbon (SC-CO_2) is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions). This section discusses the development of the SC-CO_2 estimates and the analyses in Chapter 5 apply the SC-CO_2 estimates to illustrate the value to society of the difference in CO_2 emissions among different generation technologies.

The SC-CO_2 estimates used in these analyses were developed over many years, using the best science available, and with multiple opportunities for input from the public, which is discussed further below.[44] Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. As noted in the Government Accountability Office's 2014 review, this interagency working group (1) used consensus-based decision-making, (2) relied on existing academic literature and modeling, and (3) took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated research became available.

The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. As discussed further below, the IWG published two minor corrections to the SC-CO_2 estimates in July 2015. These estimates are published in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* ("current SC-CO_2 TSD") and henceforth we refer to them as the "SC-CO_2 estimates."

The SC-CO_2 estimates were developed using an ensemble of the three most widely cited integrated assessment models in the economics literature with the ability to estimate the SC-CO_2. A key objective of the IWG was to draw from the insights of the three models while respecting the different approaches to linking GHG emissions and monetized damages taken by modelers in the published literature. After conducting an extensive literature review, the interagency group selected three sets of input parameters (climate sensitivity, socioeconomic and emissions trajectories, and discount rates) to use consistently in each model. All other model features were left unchanged, relying on the model developers' best estimates and judgments, as informed by the literature. Specifically, a common probability distribution for the

[44] Ample opportunity for public comment on all aspects of the SC-CO_2 estimates has been provided, including the estimates selected by the IWG in 2009 and in the numerous proposed rules issued by the EPA and other federal agencies between February 2010 and May 2013 that made use of the estimates.

equilibrium climate sensitivity parameter, which informs the strength of climate's response to atmospheric GHG concentrations, was used across all three models. In addition, a common range of scenarios for the socioeconomic parameters and emissions forecasts were used in all three models. Finally, the marginal damage estimates from the three models were estimated using a consistent range of discount rates, 2.5, 3.0, and 5.0 percent. See the 2010 SC-CO_2 TSD for a complete discussion of the methods used to develop the estimates and the key uncertainties, and the current SC-CO_2 TSD for the latest estimates.

The SC-CO_2 estimates represent global measures because of the distinctive nature of the climate change, which is highly unusual in at least three respects. First, emissions of most GHGs contribute to damages around the world independent of the country in which they are emitted. The SC-CO_2 must therefore incorporate the full (global) damages caused by GHG emissions to address the global nature of the problem. Second, the U.S. operates in a global and highly interconnected economy, such that impacts on the other side of the world can affect our economy. This means that the true costs of climate change to the U.S. are larger than the direct impacts that simply occur within the U.S. Third, climate change represents a classic public goods problem because each country's reductions benefit everyone else and no country can be excluded from enjoying the benefits of other countries' reductions, even if it provides no reductions itself. In this situation, the only way to achieve an economically efficient level of emissions reductions is for countries to cooperate in providing mutually beneficial reductions beyond the level that would be justified only by their own domestic benefits. In reference to the public good nature of mitigation and its role in foreign relations, thirteen prominent academics noted that these "are compelling reasons to focus on a global [SC-CO_2]" in a recent article on the SC-CO_2 (Pizer et al., 2014). In addition, as noted in OMB's Response to Comments on the SC-CO_2, there is no bright line between domestic and global damages. Adverse impacts on other countries can have spillover effects on the United States, particularly in the areas of national security, international trade, public health and humanitarian concerns.[45]

The 2010 SC-CO_2 TSD noted a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding

[45] See: (1) Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,535 (Dec. 15, 2009) and (2) National Research Council: *Climate and Social Stress: Implications for Security Analysis.* Washington, DC: The National Academies Press, 2013.

risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research.[46] The limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult. These individual limitations do not all work in the same direction in terms of their influence on the SC-CO_2 estimates, though taken together they suggest that the SC-CO_2 estimates are likely conservative. In particular, the IPCC Fourth Assessment Report (2007), which was the most current IPCC assessment available at the time of the IWG's 2009-2010 review, concluded that "It is very likely that [SC-CO_2 estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts." Since then, the peer-reviewed literature has continued to support this conclusion. For example, the IPCC Fifth Assessment report observed that SC-CO_2 estimates continue to omit various impacts that would likely increase damages. The 95th percentile estimate was included in the recommended range for regulatory impact analysis to address these concerns.

The EPA and other agencies have continued to consider feedback on the SC-CO_2 estimates from stakeholders through a range of channels, including public comments on this rulemaking and others that use the SC-CO_2 in supporting analyses and through regular interactions with stakeholders and research analysts implementing the SC-CO_2 methodology used by the interagency working group. The SC-CO_2 comments received on this rulemaking covered a wide range of topics including the technical details of the modeling conducted to develop the SC-CO_2 estimates, the aggregation and presentation of the SC-CO_2 estimates, and the process by which the SC-CO_2 estimates were derived. The EPA Response to Comments document provides a summary and response to the SC-CO_2 comments submitted to this rulemaking.

Many of the comments the EPA received in this proceeding mirrored those that OMB received in response to a separate request for public comment on the approach used to develop the estimates and the EPA has carefully considered those comments and responses here. After careful evaluation of the full range of comments submitted to OMB, the IWG continued to recommend the use of these SC-CO_2 estimates in regulatory impact analysis. The

[46] Climate change impacts and SCC modeling is an area of active research. For example, see: (1) Howard, Peter, "Omitted Damages: What's Missing from the Social Cost of Carbon." March 13, 2014, http://costofcarbon.org/files/Omitted_Damages_Whats_Missing_From_the_Social_Cost_of_Carbon.pdf; and (2) Electric Power Research Institute, "Understanding the Social Cost of carbon: A Technical Assessment," October 2014, www.epri.com.

IWG remains committed to ensuring that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change. In light of this commitment, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine.[47] The Academies process will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates.

OMB also has published a revised TSD that informed our analysis here. The revision to the TSD is limited to two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised recommended SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 revision to the May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.[48]

The EPA has examined the minor technical corrections in the revised TSD and the public comments—including those submitted to OMB's separate SC-CO_2 comment process—here as part of its consideration of whether and how to use SC-CO_2 estimates in this proceeding. Based on this examination, the EPA concurs with the consensus-based interagency working group, of which it is an active member, and finds that it is reasonable, and scientifically appropriate, to use the current SC-CO_2 estimates for purposes of analysis here.

The four SC-CO_2 estimates the EPA is selecting to use in its analysis here are as follows: \$13, \$41, \$62, and \$120 per short ton of CO_2 emissions in the year 2022 (2011\$).[49] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. SC-CO_2 estimates for several discount rates are included because the literature shows that the SC-CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context

[47] See https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions

[48] The TSDs report SC-CO_2 estimates in dollars per metric ton. The impact of the correction does not change with the conversion to short tons.

[49] The current version of the TSD is available at http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. The 2010 and 2013 TSDs present SC-CO_2 in 2007\$ per metric ton. The unrounded estimates from the current TSD were adjusted to (1) short tons for using conversion factor 0.90718474 and (2) 2011\$ using the GDP Implicit Price Deflator (1.0613744) from the National Income and Product Accounts Tables; the unrounded 2011\$ estimates are used in the Chapter 5 illustrative analysis. The RIA presents SC-CO_2 estimates rounded to two significant digits.

(where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO_2 from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC-CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

Table 3-1 presents the global SC-CO_2 estimates for the years 2015 to 2050. In order to calculate the dollar value for emission reductions, the SC-CO_2 estimate for each emissions year would be applied to changes in CO_2 emissions for that year, and then discounted back to the analysis year using the same discount rate used to estimate the SC-CO_2. The SC-CO_2 increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change. Note that the interagency group estimated the growth rate of the SC-CO_2 directly using the three integrated assessment models rather than assuming a constant annual growth rate. This helps to ensure that the estimates are internally consistent with other modeling assumptions.

Table 3-1. Social Cost of CO_2, 2015-2050[a] (in 2011$)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$11	$35	$54	$100
2020	$12	$41	$60	$120
2022	$13	$41	$62	$120
2025	$13	$44	$65	$130
2030	$15	$48	$70	$150
2035	$17	$53	$75	$160
2040	$20	$58	$81	$180
2045	$22	$62	$86	$190
2050	$25	$66	$90	$200

[a] These SC-CO_2 values are stated in $/short ton and rounded to two significant figures. Unrounded estimates from the current TSD have been converted from $/metric ton to $/short ton using conversion factor 0.90718474 for consistency with this rulemaking and adjusted to 2011$ using the GDP Implicit Price Deflator (1.0613744). This calculation does not change the underlying methodology nor does it change the meaning of the SC-CO_2 estimates. For both metric and imperial denominated SC-CO_2 estimates, the values vary depending on the year of CO_2 emissions and are defined in real terms. The unrounded 2011$ estimates are used in the Chapter 5 illustrative analysis. The SC-CO_2 estimates shown in this table have been rounded to two significant digits.

3.3 Health Co-Benefits of SO_2 and NOx Reductions

The EPA anticipates that this rule will result in negligible emission changes over the baseline by 2022. However, if CO_2 emissions are reduced from new EGUs under this rule, then emissions of other pollutants from the power sector would also likely be reduced. For example, reducing CO_2 emissions through the adoption of CCS by coal-fired boilers may also yield sulfur dioxide (SO_2) and emission reductions, which in turn would yield health benefits. We refer to these additional benefits as "co-benefits".

SO_2 is a precursor for fine particulate matter formation, which is particulate matter 2.5 micrometers in diameter and smaller ($PM_{2.5}$), while NO_X is a precursor for $PM_{2.5}$ and ground-level ozone formation. As such, reductions of SO_2 and NO_X would in turn lower overall ambient concentrations of $PM_{2.5}$ and ozone. Reducing exposure to $PM_{2.5}$ and ozone is associated with human health benefits including avoided mortality and morbidity. Researchers have associated $PM_{2.5}$ and ozone exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies (U.S. EPA, 2009; U.S. EPA, 2013a). Health effects associated with exposure to $PM_{2.5}$ include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks and hospital admissions, and respiratory morbidity such as asthma attacks, bronchitis, hospital and emergency room visits, work loss days, restricted activity days, and respiratory symptoms. Health effects associated with exposure to ozone include premature mortality and respiratory morbidity such as hospital admissions, emergency room visits, and school loss days. In addition to human health co-benefits associated with $PM_{2.5}$ and ozone exposure, reducing SO_2 and NO_X emissions under this rule would result in reduced health impacts from direct exposure to these pollutants. For example, ambient concentrations of SO_2 are associated with respiratory symptoms in children, emergency department visits, and hospitalizations for respiratory conditions.

Reducing SO_2 and NO_X emissions would also result in other human welfare (non-health) improvements including improvements in ecosystem services. SO_2 and NO_X emissions can adversely impact vegetation and ecosystems through acidic deposition and nutrient enrichment, and can affect certain manmade materials, visibility, and climate (U.S. EPA, 2009; U.S. EPA, 2008).

The avoided incidences of health effects and monetized value of health or non-health improvements that result from SO_2 and NO_x emissions reductions depend on the location of those reductions. For a full discussion of the human health, ecosystem and other benefits of reducing SO_2 and NO_X emissions from power sector sources, please refer to the Regulatory Impact Analysis for the Final Carbon Pollution Guidelines for Existing Power Plants (U.S. EPA, 2015).

As described in Chapter 4, the EPA anticipates that this rule will result in no emission changes by 2022. As a result we did not need to perform a full health co-benefit impact assessment for a specific modeled compliance scenario. In Chapter 5, the EPA presents results for several illustrative plant-level analyses that show the potential impacts of the rule if certain key assumptions were to change substantially. When assessing the co-benefits of differences in emissions from different generation technologies in Chapter 5, the EPA does not assume a specific location for the illustrative new unit.[50] Instead, the EPA relied on a national-average benefit per-ton (BPT) method to estimate $PM_{2.5}$-related health impacts of SO_2 and NO_X emissions. The BPT approach provides an estimate of the total monetized human health benefits (the sum of premature mortality and morbidity) of reducing one ton of $PM_{2.5}$ precursor (i.e., NO_X and SO_2) from the sector. To develop the BPT estimates used in this analysis the EPA utilized detailed air quality modeling of the entire power sector SO_2 and NO_X emissions along with the BenMAP model[51] to estimate the benefits of air quality improvements using projected 2020 population, baseline incidence rates, and economic factors.

The SO_2- and NO_X-related BPT estimates utilized in this analysis are derived from the TSD on estimating the BPT of reducing $PM_{2.5}$ and its precursors (U.S. EPA, 2013b). These BPT values are estimated in a methodologically consistent manner with those reported in Fann et al. (2012). They differ from those reported in Fann et al. (2012) as they reflect the health impact studies and population data updated in the benefits analysis of the final PM NAAQS RIA (U.S. EPA, 2012). The recalculation of the Fann et al. (2012) BPT values based on the updated data from the PM NAAQS RIA (U.S. EPA, 2012) is described in the TSD (U.S. EPA, 2013b). The BPT values are for the entire electricity sector and are not differentiated by fuel or generator type.

The methods used for this analysis are consistent with those used to estimate the health co-benefits from secondary $PM_{2.5}$ formation for the Regulatory Impact Analysis for the Final Carbon Pollution Guidelines for Existing Power Plants (U.S. EPA, 2015). One notable difference between the BPT values used in the two analyses is that this analysis utilizes national-average BPT estimates because the EPA does not assert a specific location for the illustrative new unit, whereas the BPT estimates used in the RIA for the final existing source guidelines differ by region.[52]

Despite our attempts to quantify and monetize as many of the co-benefits of reducing

[50] If the EPA assumed a location for a particular new unit it may be possible to perform a full health impact assessment of different technology options for generating electricity at that location. Doing so for a number of locations is beyond the scope of this analysis and would be better captured in sector-wide modeling.

[51] Available at http://www.epa.gov/air/benmap.

[52] Separate BPT values are generated for California, the Eastern U.S., and the Western U.S. excluding California. For further information, see EPA 2015.

emissions from electricity generating sources as possible, not all known health and non-health co-benefits from reducing SO_2 and NO_x are accounted for in this assessment. For more information about unquantified health and non-health co-benefits of SO_2 and NO_x please refer to tables 5-2 and 6-2 of the PM NAAQS RIA (U.S. EPA, 2012), respectively. Furthermore, the analysis that follows does not account for known differences in other air and water pollutants between the different generating technologies, including, for example, ozone or directly-emitted PM. The implications for limiting our consideration of co-benefits to pollutants that cause secondary $PM_{2.5}$ is discussed in Chapter 5.

As we do not assume a specific location for the new units being compared, this RIA is unable to include the type of detailed uncertainty assessment found in the RIA for the National Ambient Air Quality Standards for Particulate Matter (PM NAAQS RIA) (U.S. EPA, 2012). However, the results of the uncertainty analyses presented in the PM NAAQS RIA can provide some information regarding the uncertainty inherent in the benefits results presented in this analysis. In addition to the uncertainties described in the PM NAAQS RIA, the use of BPT estimates come with additional uncertainty. Specifically, these national-average BPT estimates reflect a specific geographic distribution of SO_2 and NO_X reductions resulting in a specific reduction in $PM_{2.5}$ exposure and may not fully reflect local or regional variability in population density, meteorology, exposure, baseline health incidence rates, timing of emissions, or other factors that might lead to an over-estimate or under-estimate of the actual benefits associated with $PM_{2.5}$ precursors in a specific location. These estimates are illustrative as the EPA does not assume a specific location for the illustrative electricity generation technologies and is therefore unable to specifically determine the population that would be affected by their emissions. Therefore, the benefits for any specific unit can be different than the estimates shown here.

Notwithstanding these limitations, reducing one thousand tons of annual SO_2 from U.S. power sector sources has been estimated to yield between four and nine incidences of premature mortality avoided and monetized $PM_{2.5}$-related health benefits (including these incidences of premature mortality avoided) between $38 million and $85 million in 2020 (2011$) using a 3 percent discount rate or between $34 million and $76 million (2011$) using a 7 percent discount rate. Additionally, reducing one thousand tons of annual NO_X from U.S. EGUs has been estimated to yield up to one incidence of premature mortality avoided and monetized $PM_{2.5}$-related health benefits (including these incidences of premature mortality avoided) of between $5.5 million and $12 million in 2020 (2011$) using a 3 percent discount rate or between $5.0 million and $11 million (2011$) using a 7 percent discount rate. For each pollutant, the range of estimated benefits for each discount rate is due to the EPA's use of two alternative primary estimates of $PM_{2.5}$-related mortality impacts: a lower primary estimate based on Krewski et al. (2009) and a higher primary estimate based on Lepeule et al. (2012). The benefit per ton values are reported in Table 3-2.

Table 3-2. Monetized Health Benefits Per Ton of $PM_{2.5}$ Precursor Reductions in 2020[a] (in 2011$)

	$PM_{2.5}$ Precursor	
	SO_2	**NO_X**
3% Discount Rate		
Krewski et al. (2009)	$38,000	$5,500
Lepeule et al. (2012)	$85,000	$12,000
7% Discount Rate		
Krewski et al. (2009)	$34,000	$5,000
Lepeule et al. (2012)	$76,000	$11,000

[a] These estimates are from U.S. EPA, 2013a (electricity generating units) and are adjusted to 2011$ using the Gross Domestic Product implicit price deflator reported by the Department of Commerce.

3.4 References

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CHAPTER 4
COSTS, ECONOMIC, AND ENERGY IMPACTS OF THE NEW SOURCE STANDARDS

4.1 Synopsis

This chapter reports the compliance cost, economic, and energy impact analyses performed for the final EGU New Source GHG Standards.[53] The U.S. Environmental Protection Agency (EPA) analyzed and assessed a wide range of potential scenarios and outcomes, using a detailed power sector model, other government projections for the power sector, and additional economic assessments and analyses to determine the potential impacts of this action.

The primary finding of this assessment is that in the baseline, all projected unplanned[54] capacity additions affected by these standards during the analysis period would already be compliant with the rule's requirements (e.g., natural gas combined cycle units, low capacity factor natural gas combustion turbines, and small amounts of coal-fired units with carbon capture and storage (CCS) supported by federal and state funding). The analysis period is defined as through 2022[55] to reflect that CAA Section 111(b) requires that the NSPS be reviewed every eight years. The EPA's conclusion was based on:

- EIA power sector modeling projections,
- EPA power sector modeling projections,
- Electric utility integrated resource planning (IRP) documents, and
- Projected new EGUs reported by industry to the U.S. Energy Information Adminstration (EIA).

The EPA's forecast of no new non-compliant coal-fired capacity remains robust beyond the analysis period (past 2030 in both EIA and EPA baseline modeling projections) and across a wide range of alternative potential market, technical, and regulatory scenarios that influence power sector investment decisions. As a result, the EGU New Source GHG Standards are not

[53] Chapter 6 reports the compliance cost, economic, and energy impact analyses performed for the final EGU Modified and Reconstructed Source Standards.
[54] Unplanned capacity represents projected capacity additions that are not under construction.
[55] In some cases, conditions in the analysis year of 2022 are represented by results of power sector modeling for the year 2020. An analysis year of 2023 (8 years from finalization) would not substantively alter the overall conclusions of this RIA. Integrated Planning Model (IPM) output for subsequent years has been made available in the docket and is discussed where appropriate throughout the document.

expected to change GHG emissions for newly constructed EGUs, and are anticipated to yield no monetized benefits and impose negligible costs, economic impacts, or energy impacts on the electricity sector or society. While the EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this rule, this chapter presents an analysis of the project-level costs of building new coal-fired capacity with and without CCS to demonstrate that a requirement of partial CCS would not preclude new coal construction due to economic conditions. An additional illustrative analysis, presented in Chapter 5, shows that even in the unlikely event that new, non-compliant EGU capacity would be built, the final EGU New Source GHG Standards would provide net social benefits under a range of assumptions.

4.2 Requirements of the Final GHG EGU NSPS

In this action, the EPA is finalizing standards of performance for two basic categories of new units that have not commenced construction by January 8, 2014: (i) fossil fuel-fired electric utility steam generating units (boilers and IGCC units) and (ii) natural gas-fired stationary combustion turbines that generate electricity for sale and meet certain applicability criteria.

The EPA is finalizing standards of performance for affected EGUs within the following two categories: (1) all fossil fuel-fired steam generating units (steam generating units, boilers and integrated gasification combined cycle (IGCC) units), and (2) all natural gas-fired stationary combustion turbines, regardless of the size of the stationary turbine unit. All affected new fossil fuel-fired EGUs would be required to meet an output-based emission rate of a specific mass of carbon dioxide (CO_2) per megawatt-hour (MWh) of electricity generated energy output on a gross basis.

New fossil fuel-fired steam generating units (boilers and IGCC units) would be required to meet an emission standard of 1,400 lb CO_2/MWh of gross energy output.

Newly constructed natural gas-fired stationary combustion turbines will be required to meet a standard of 1,000 lb CO_2/MWh of gross energy output (or 1,030 lb CO_2/MWh of net energy output). This emission limit applies to all affected natural gas-fired stationary combustion units regardless of size. The natural gas combustion turbine standard, however, will only apply to units that will exceed a sales threshold on the amount of electricity generated that is sold to the electric grid. The purpose of the sales threshold criterion is to permit gas-fired combustion turbines that only sell a small portion of the gross electricity generated to the grid ("peaking units") to not have to meet the same emission standard as a combustion turbine unit designed primarily to generate base and intermediate electricity to be sold to the grid.

Please refer to the preamble for additional detail concerning affected EGUs and standards of performance.

4.3 Power Sector Modeling Framework

4.3.1 Modeling Overview

Over the last decade, the EPA has conducted extensive analyses of regulatory actions impacting the power sector. These efforts support the Agency's understanding of key policy variables and provide the framework for how the Agency estimates the costs and benefits associated with its actions that impact the power sector. Current forecasts for the utilization of new and existing generating capacity are a key input into evaluating the impact of this rule. Given excess capacity within the existing fleet and relatively low forecasts of electricity demand growth, there is limited new capacity of any type expected to be constructed over the next decade. A small number of new coal-fired power plants have been completed and brought online in recent years. However, the EPA does not expect the construction of any new non-compliant coal-fired capacity through the analysis period. The EPA also does not expect any new non-compliant natural gas-fired stationary combustion turbines meeting the applicability criteria to be built. This conclusion is based in part on the Agency's own power sector modeling utilizing the Integrated Planning Model (IPM) as well as EIA's Annual Energy Outlook 2014 (AEO 2014) projections.

IPM, developed by ICF International, Inc, is a state-of-the-art, peer reviewed, dynamic linear programming model that can be used to project power sector behavior under future business as usual conditions and examine prospective air pollution control policies throughout the United States for the entire electric power system. The EPA used IPM to project likely future electricity market conditions with and without this rule.

In addition to using IPM, the EPA has closely examined modeling results from a number of alternative baseline scenarios in the AEO 2014 from the EIA. To produce the AEO, EIA employs the National Energy Modeling System (NEMS), an energy-economy modeling system of the United States. According to EIA:[56]

> NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.

[56] http://www.eia.gov/oiaf/aeo/overview/

The Electricity Market Module of NEMS produces projections of power sector behavior that minimize the cost of meeting electricity demand subject to the sector's inherent constraints, including the availability of existing generation capacity, transmission capacity and cost, cost of utility and nonutility technologies, expected load shapes, fuel markets, regulations, and other factors. EIA's AEO projections independently corroborate the EPA's conclusions in that the forecast no new generation capacity being constructed through the analysis period that would not already meet the final new source standards. Both the IPM and AEO 2014 NEMS modeling results are presented in Section 4.4.

4.3.2 The Integrated Planning Model

IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades to better understand power sector behavior under future business as usual conditions and evaluate the economic and emission impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible.[57] The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[58,59]

Although the Agency typically focuses on broad system effects when assessing the economic impacts of a particular policy, the EPA's application of IPM includes a detailed and sophisticated regional representation of key power sector variables and its organization. When considering which new units are most cost effective to build and operate, the model considers the relative economics of various technologies based on a wide spectrum of current and future considerations, including capital costs, operation and maintenance costs, fuel costs, utility sector regulations, and emission profiles. The capital costs for new units account for regional differences in labor, material, and construction costs. These regional cost differentiation factors were developed based on data and assumptions used in the EIA's AEO 2013.

As part of IPM's assessment of the relative economic value of building a new power plant, the model incorporates a detailed representation of the fossil-fuel supply system that is

[57] http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html
[58] http://www.epa.gov/airmarkets/programs/ipm/psmodel.html
[59] http://www.epa.gov/airmarkets/documents/ipm/EPA_Base_Case_v514_Incremental_Documentation.pdf

used to forecast equilibrium fuel prices, a key component of new power plant economics. The model includes an endogenous representation of the North American natural gas supply system through a natural gas module that reflects full supply/demand equilibrium of the North American gas market. This module consists of 118 supply, demand, and storage nodes, 15 liquefied natural gas regasification facility locations and three LNG export facility locations that are tied together by a series of linkages (i.e., pipelines) that represent the North American natural gas transmission and distribution network.

IPM also endogenously models the coal supply and demand system throughout the continental U.S., and reflects non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 465 coal supply curves for each of nine years, 14 coal sulfur grades, and the coal transport network, which consists of 4,947 linkages representing the costs of transporting coal via rail, barge, and truck and conveyer linkages connecting 41 regions with 575 individual coal-fired generating stations. The coal supply curves and the transport network costs used in IPM are publicly available,[60] and were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants will face over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 84 coal supply curves. These curves have been independently reviewed by industry experts and have been made available for public review on several occasions over the past two years during other rulemaking processes.

The EPA has used IPM extensively over the past two decades to analyze options for reducing power sector emissions. The model has been used to forecast the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (CAIR), Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the proposed GHG emission guidelines for existing source EGUs.[61] Recently IPM has also been used to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule, Disposal of Coal Combustion Residuals from Electric Utilities (CCR) and Steam Electric Effluent Limitation Guidelines (ELG).

The model undergoes periodic formal peer review, which includes separate expert

[60] The IPM coal supply curves are presented in detail in Appendix 9-24 of the IPM Base Case documentation, which is available at http://www.epa.gov/airmarkets/programs/ipm/psmodel.html. The coal transport network costs are in Appendix 9-23, available at that same link.

[61] The IPM projection conducted for this rulemaking is available at the EPA's website and in the public docket.

panels for both the model itself and the EPA's key modeling input assumptions.[62] The rulemaking process also provides opportunity for expert review and comment by stakeholders, including owners and operators of the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The EPA is required to respond to significant comments submitted regarding the inputs used in IPM, its structure, and application. The feedback that the Agency receives provides a detailed check for key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, from the mid-1990s through 2011 the Science Advisory Board reviewed IPM as part of the Clean Air Act (CAA) Amendments Section 812 studies of the CAA costs and benefits that are periodically conducted.[63] The model has also undergone considerable interagency scrutiny when it has been used to conduct over one dozen legislative analyses performed at Congress' request over the past decade. In addition, Regional Planning Organizations throughout the U.S. have extensively examined IPM as a key element in the state implementation plan (SIP) process for achieving the National Ambient Air Quality Standards. The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 15 years.

IPM has also been employed by state partnerships (e.g., the Regional Greenhouse Gas Initiative (RGGI), the Western Regional Air Partnership, Ozone Transport Assessment Group), other federal and state agencies, environmental groups, and industry, all of whom subject the model to their own review procedures. States have also used the model extensively to inform issues related to ozone in the northeastern U.S. This groundbreaking work set the stage for the NO_x SIP call, which has helped reduce summer nitrogen oxide (NO_x) emissions and the formation of ozone in densely populated areas in the northeast.

4.4 Analyses of Future Generating Capacity

4.4.1 Base Case Power Sector Modeling Projections

The "base case" for this analysis is a business-as-usual scenario that would be expected under market and regulatory conditions in the absence of this rule. As such, the IPM base case represents the baseline for this regulatory impact analysis. The EPA frequently updates the IPM base case to reflect the latest available electricity demand forecasts, as well as expected costs and availability of new and existing generating resources, fuels, and emissions control technologies.

[62] http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html
[63] http://www.epa.gov/air/sect812/index.html

The EPA conducted analysis and modeling in support of the April 2012 EGU GHG New Source Standards proposal, and concluded that new unplanned non-compliant base load power plants are not expected to be built through the analysis period (2020 for the original proposal) and beyond (77 FR 22392, April 13, 2012). The EPA conducted an analysis of the economic impacts by modeling a base case scenario of future electricity market conditions. The EPA's IPM modeling for the 2012 proposal utilized the IPM v. 4.10 base case, and relied on the AEO 2010 for the electric demand forecast for the U.S. and employed a set of the EPA's assumptions regarding fuel supplies, the performance and cost of electric generation technologies, pollution controls, and numerous other parameters. For the 2012 proposal, the EPA also conducted three additional base case sensitivity analyses using IPM.[64]

After considering public comments received on the 2012 proposal, the EPA issued a new proposal for carbon emissions from new power plants (79 FR 1430, January 8, 2014). The EPA's IPM modeling of the 2013 proposal relied on the AEO 2013 electric demand forecast, and was analyzed using the IPM v. 5.13 base case. The EPA also conducted three additional base case sensitivity analyses using IPM.[65]

For the analysis of the final rule, the EPA used the IPM v. 5.14 base case, which relied on the electric demand forecast in AEO 2014. The v. 5.14 base case updated v. 5.13 unit level specifications (including control configurations) based on comments received and EGU compliance plans in response to environmental regulations. The base case accounts for the effects of the finalized MATS and CSAPR rules, New Source Review settlements and state rules through 2014 impacting sulfur dioxide (SO_2), NO_x, directly emitted particulate matter and CO_2, and final actions the EPA has taken to implement the Regional Haze Rule. The EPA's IPM base case also includes two federal non-air rules effecting EGUs: the Cooling Water Intakes (316(b)) Rule and the Disposal of Coal Combustion Residuals from Electric Utilities Rule (CCR).

Table 4-1 reports the unplanned capacity additions forecast by the IPM base case. Unplanned capacity additions are those that the model forecasts to be built in response to forecast economic conditions, such as fuel prices and demand growth. The EPA's IPM base case forecast finds that EGUs are projected to adopt technology for new steam and combustion turbine generation capacity that would be compliant with the standards, even in the absence of this rule. Only some new coal-fired units with carbon capture and storage (CCS) technology, which are receiving partial federal financial support, are included in the baseline modeling.

[64] http://www2.epa.gov/sites/production/files/2013-09/documents/20120327proposalria.pdf
[65] http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf and http://www.epa.gov/airmarkets/programs/ipm/proposedEGU_GHG_NSPS.html

Furthermore, new simple-cycle combustion turbines (CTs) constructed in the EPA's IPM base case are assumed to operate at an emissions rate above the standard. However, mirroring real world behavior, relatively low levels of CT generation are projected in the base case. In the base case new CTs are forecast to operate, on average in each domestic model region, at capacity factors well below the applicability requirements of this rule. In the base case the maximum average capacity factor for individual new CTs is 14 percent or less across all domestic regions and all simulation years. The emissions rate of new natural gas combined cycle (NGCC) units in the EPA's IPM base case is below the emissions rate standard of this final rule, although this is by assumption. However, assuming an emissions rate for new NGCC units that is below the emissions rate standard is consistent with the detailed emissions rate analysis described in the preamble for this rule. That analysis carefully considered emissions rate data on newly constructed NGCC units and GHG limitations in recently issued construction permits for NGCC facilities and found that these facilities operated below the standard or were permitted to operate below the standard.

The EIA projections that are reflected in AEO 2014 reference case are summarized in the following tables alongside the EPA base case projections. According to the EIA, the AEO 2014 reference case "projection is a business-as-usual trend estimate, given known technology and technological and demographic trends."[66] It represents existing policies and regulations influencing the power sector.[67] As shown in Table 4-1, new coal-fired capacity through 2030 is projected to be entirely CCS-equipped and would be in compliance with these standards (300 MW) in the AEO 2014 reference case. The projected CCS-equipped capacity is assumed to occur in response to existing federal, state, and local incentives for the technology.[68] The AEO 2014 reference case forecasts that the vast majority of new, unplanned generating capacity will be either natural gas-fired or renewable.[69] The reference case projects a capacity factor for simple cycle combustion turbines of less than 20 percent in all regions and in all years, and therefore these units are projected to operate below the applicability limit for this final rule. As in the IPM-based analysis, the emission rate for new NGCC units in the AEO 2014 reference case is assumed to be below the applicable standard in this final rule.

As described in detail in 4.4.2, the economics favoring new natural gas combined cycle

[66] http://www.eia.gov/forecasts/archive/aeo14/pdf/0383(2014).pdf

[67] Reference case assumptions are described in Assumptions to the Annual Energy Outlook 2014 (U.S. EIA 2014b).

[68] These programs include the Emergency Economic Stabilization Act of 2008, the American Reinvestment and Recovery Act of 2009 (which assisted in funding for such programs as the Clean Coal Power Initiative through DOE and tax credits for Clean Energy Manufactures through DOE and the Treasury Department), as well as loans provided by USDA for CO_2 capture projects. See also preamble section 3.H.3.g discussing the EPAct 2005.

[69] http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm

(NGCC) additions instead of coal-fired additions are robust under a range of sensitivity cases examined in the AEO 2014. Sensitivity cases that EIA conducted in the AEO 2014, as well as the AEO 2013, separately examine higher economic growth, lower coal prices, no risk premium for greenhouse gas emissions liability from conventional coal, and lower oil and natural gas resources. None of these sensitivity cases forecast unplanned additions of coal-fired capacity without CCS in the analysis period. This has been a consistent finding in the AEO, which led the Department of Energy (DOE) to conclude that "the low capital expense, technical maturity, and dispatchability of natural gas generation are likely to dominate investment decisions under current policies and projected prices."[70]

Table 4-1. Unplanned Cumulative Capacity Additions (GW)

	EPA Base Case	AEO 2014 Reference Case		
Capacity Type	**2020**	**2020**	**2025**	**2030**
Conventional Coal	0	0	0	0
Coal with CCS	0.3	0.3	0.3	0.3
Natural Gas CC	6.9	9.8	28.8	95.7
Natural Gas CT	2.6	14.1	34.5	49.2
Nuclear	0	0	0	0
Renewables[71]	15.9	17.4	19.3	22.5
Distributed Generation[72]	-	1.6	3.3	4.6
Total	**25.8**	**43.2**	**86.3**	**141.4**

Notes: The sum of the table values in each column may not match the total figure due to rounding. EPA capacity data is net nameplate capacity, AEO capacity data is net summer generating capacity.
Source: EPA 2020 projection from IPM v. 5.14 base case; EIA 2020-2030 projection from EIA Annual Energy Outlook 2014, Table A9.

The capacity projections of EIA and the EPA represent a continuation of current trends, where natural gas-fired capacity has been the technology of choice for base load and

[70] Department of Energy (2011). *Report on the First Quadrennial Technology Review. Available at http://energy.gov/sites/prod/files/QTR_report.pdf.*

[71] Renewable projections in 2020 are larger in the AEO 2014 reference case than in the EPA's IPM v 5.14 base case primarily due to differences in modeling assumptions regarding the amount of 'planned' renewable capacity additions and 'unplanned' additions in the AEO forecast. The overall amount of total renewable capacity in use by 2020 is largely similar in the two forecasts. The EPA planned cumulative renewable capacity additions include utility-scale onshore wind, solar PV, geothermal and biomass built between 2015 and 2020. The AEO 2014 unplanned renewable capacity additions includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, biomass (not co-fired with coal), PV and thermal solar, and wind power built between 2012 and 2020.

[72] The term "Distributed Generation" refers to two different concepts. AEO defines the term distributed generation as "primarily peak-load capacity fueled by natural gas." The EPA forecasts using the IPM model do not model new construction of distributed generation or capacity, which in the IPM model refers to small scale generation such as roof top PV, household geothermal, etc. Such small scale generation does not generate net electricity that can be sold to the grid, although it can reduce peak load demands on the grid system.

intermediate load power generation over the last few years (see Figure 4-1), due in large part to its significant levelized cost of electricity[73] (LCOE) advantage over coal-fired generating technologies. A greater discussion of the relative LCOE of different generating technologies is provided beginning in Section 4.4.

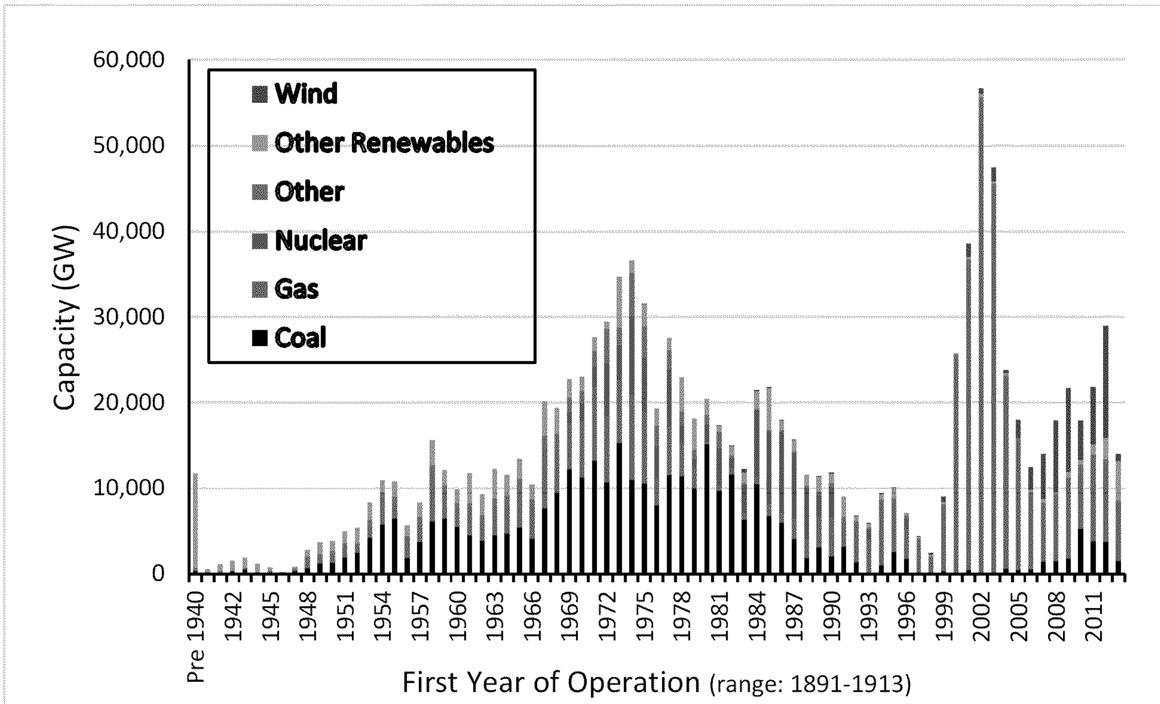

Figure 4-1. Historical U.S. Power Plant Capacity Additions, by Technology, 1891-2013

Source: Form EIA-860 (2013)
Notes: Figure reflects all capacity brought online from 1891 – 2013, including 77 GW subsequently retired. Total capacity shown: 1,126 GW, including 12 GW built pre-1940. Other Renewables include: hydro, biomass, solar, landfill gases, solid waste combustion and geothermal. Other includes: petroleum & distillates, petroleum coke, propane, other gases and waste heat not otherwise included.

In addition to new builds, increased electricity demand is expected to be partially fulfilled by increased utilization of existing generating capacity. Generation projections are the result of least-cost economic modeling both in IPM and AEO 2014, and reflect the most cost-effective dispatch and investment decisions modeled, given a variety of variables and constraints. Even without the deployment of new conventional coal-fired capacity, U.S. electricity demand will continue to be met by a diverse mix of electricity generation sources with coal projected to continue to provide the largest share of electricity (36 percent of total 2020 generation in AEO 2014 and 37 percent in the EPA's projections), as displayed in Table 4-2.

[73]The levelized cost of electricity is an economic assessment of the cost of electricity from a new generating unit or plant, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital.

Table 4-2. 2012 U.S. Electricity Net Generation and Projections for 2020, 2025, and 2030 (Billion kWh)

	Historical	EPA Base Case	AEO 2014 Reference Case		
	2012	**2020**	**2020**	**2025**	**2030**
Coal	1,512	1,534	1,646	1,689	1,692
Oil	23	47	18	19	19
Natural Gas	1,228	1,156	1,286	1,410	1,552
Nuclear	769	815	779	711	782
Hydroelectric	274	282	288	291	294
Wind	142	251	218	218	219
Other Renewables	48	121	102	133	154
Other	71	-7	65	151	103
Total	**4,067**	**4,199**	**4,402**	**4,622**	**4,815**

Source: Historical data from Form EIA-860, 2012. EPA 2020 projection from IPM 5.14 base case; EIA 2020-2030 projection from EIA Annual Energy Outlook 2014, Tables A8 and A16

Notes: The sum of the table values in each column may not match the total figure due to rounding. "Other Renewables" include biomass, geothermal, waste and solar electric generation capacity. "Other" includes pumped storage (net loss, non-biogenic waste, batteries, hydrogen, and other miscellaneous generation and storage technologies. Negative value reflects net energy loss from pumped storage.

It has been previously noted that the current projections for key market variables, such as natural gas prices, and state and regional regulations are now even less favorable to the development of non-compliant coal-fired capacity than at the time of the 2012 proposal. State and regional regulations have changed since the 2012 proposal, as noted in Section 2.8, most notably regulations of GHG emissions from the power sector and state renewable portfolio standards (RPS):

- State regulations addressing CO_2 emissions – Several states have adopted measures to address emissions of CO_2 from the power sector. These approaches include flexible market-based programs like California's Assembly Bill 32 and RGGI in the Northeast, and specific GHG performance standards for new power plants in California, Oregon, New York, and Washington.

- State Renewable Portfolio Standards (RPS) – There are now 29 states, the District of Columbia and Puerto Rico that have an enforceable RPS, or similar laws.[74] Eight other States, the Virgin Islands and Guam have voluntary goals. These measures, in conjunction with federal financial incentives, are key drivers of the significant growth in new renewable energy seen over the past few years and expected over the next decade. Only 12 states do not currently have an enforceable RPS.[75]

- State and Utility IRPs – IRPs, which are usually adopted by utilities in response to state requirements, allow regulators and utilities to consider a broader array of measures to meet future electric demand most cost effectively. IRPs also help electric planners to consider key strategic and policy goals like electric reliability, environmental impacts, and the economic efficiency of power sector investments.[76] In general, these plans confirm the expectation that utilities anticipate any new sources of generation will be from sources that meet the standards set in this regulation. Furthermore, these plans reflect an expectation of relatively low demand growth due, in part, to policies and regulations to reduce the electricity consumption such as energy efficiency regulations and policies, evolution of the Smart Grid, and demand response measures.

4.4.2 Alternative Scenarios from AEO 2014

As described in the previous section, in addition to the EPA's own analysis, the EPA reviewed EIA's recent forecasts of new capacity in the electricity sector for the AEO 2014. The AEO 2014 reference case forecasts no new non-compliant capacity would be built. Power sector modeling by EIA also projects that their conclusion of there being no new coal-fired capacity built in the analysis period is robust under a range of alternative assumptions that influence the industry's decisions to build new power plants. For example, EIA typically supplements the AEO with scenarios that explore key market, technical, and regulatory issues. Of the 31 scenarios contained in the AEO 2014, none project new coal-fired capacity in the analysis period used by the EPA for this RIA, including the four scenarios that may be considered most favorable to the development of coal-fired capacity displayed in Table 4-3.

[74] http://www.cesa.org/assets/2013-Files/RPS/State-of-State-RPSs-Report-Final-June-2013.pdf

[75] In January 2015 West Virginia repealed the West Virginia Alternative Renewable Energy Portfolio Act, which was enacted in 2009. E.g, http://www.governor.wv.gov/media/pressreleases/2015/Pages/GOVERNOR-TOMBLIN-APPROVES-REPEAL-OF-ALTERNATIVE-RENEWABLE-ENERGY-PORTFOLIO-ACT.aspx

[76] See Integrated Resource Plan Technical Support Document for more information.

Table 4-3. AEO 2014 Reference Case and Alternative Scenario Forecasts of Unplanned Cumulative Capacity Additions by 2020, GW

Capacity Type	Reference	High Growth	Low Coal Cost	Low Gas & Oil Resource	No GHG Concern
Conventional Coal	0	0	0	0	0
Coal with CCS	0.3	0.3	0.3	0.3	0.3
Natural Gas	23.9	34.4	19.8	16.3	22.7
Nuclear	0	0	0.0	2.5	0.0
Non-Hydro Renewables	17.4	19.7	17.6	23.7	17.5
Other	1.6	2.0	1.5	0.8	1.6
Total	**43.2**	**56.5**	**39.3**	**43.6**	**42.1**

Note: The AEO 2014 scenario definitions are: High Economic Growth increases annual real GDP growth by 2.8 percent per year through 2040 (reference case GDP growth is 2.4 percent per year); Low Coal Cost assumes 2.4 percent greater regional coal mining productivity growth than in the reference case, and lower wages, equipment, and declining transportation costs for the coal industry than in the reference case, falling to 25 percent below the reference case by 2040; Low Oil and Gas Resource reduces the ultimate estimated recovery of shale gas, tight gas, and tight oil by 50 percent; No GHG Concern removes the perceived risk of incurring costs under a future GHG policy from market investment decisions.

4.4.3 Power Sector Fuel Price Dynamics and Trends

Expectations about what new fossil-fired generation would serve future demand have changed over the past decade from generating sources that use coal to those, primarily combined cycle systems, that use natural gas. As mature technologies, the cost and performance characteristics of conventional coal-fired capacity and NGCC are projected by the EPA to be relatively stable over time.[77] Therefore, expectations of future fuel prices play a key role in determining the overall cost competitiveness of conventional coal-fired units versus NGCC units.

Current and projected natural gas prices are considerably lower than observed prices over the past decade. This is largely due to advances in hydraulic fracturing and horizontal drilling techniques that have opened up new shale gas resources and substantially increased the supply of economically recoverable natural gas. According to EIA:

> Shale gas refers to natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously

[77] http://www.epa.gov/airmarkets/documents/ipm/Chapter_4.pdf

uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States.

Of the natural gas consumed in the United States in 2011, about 95 percent was produced domestically; thus, the supply of natural gas is not as dependent on foreign producers as is the supply of crude oil, and the delivery system is less subject to interruption. The availability of large quantities of shale gas should enable the United States to consume a predominantly domestic supply of gas for many years and produce more natural gas than it consumes.[78]

The AEO 2014 projects U.S. natural gas production will increase by 13.3 trillion cubic feet (Tcf), a 55 percent increase (from 24.3 Tcf in 2014 to 37.5 Tcf in 2040). Over 75 percent of this forecast increase in domestic natural gas production is due the projected doubling of shale gas production, which is forecast to increase by 10.2 TCF (from 9.6 TCF in 2014 to 19.8 TCF in 2040).[79]

Recent historical data reported to EIA is also consistent with these trends, with 2014 being the highest year on record for domestic natural gas production.[80] Gas production in 2014 was 6.3 percent above production in 2013, which is the largest annual growth rate since 1984. The average real (2011$) natural gas price delivered to the power sector was $4.39/MMBtu in 2014, an increase from $4.25/MMBtu in 2013.[81,82]

Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. While sources may disagree on the absolute level of increases from shale resources, there is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices.[83,84] Modeling by the EPA and EIA incorporates the impact of these additional resources on the forecasts of the price of natural gas used by electric

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[78] For more information, see: http://www.eia.gov/forecasts/archive/aeo11/IF_all.cfm#prospectshale; http://www.eia.gov/energy_in_brief/about_shale_gas.cfm

[79] AEO 2014, Appendix A, Table A14. Oil and Gas Supply

[80] http://www.eia.gov/dnav/ng/hist/n9010us2a.htm

[81] http://www.eia.gov/dnav/ng/hist/n3045us3A.htm; Assumes that 1 TCF = 1.023 MMBtu natural gas (http://www.eia.gov/tools/faqs/faq.cfm?id=45&t=8)

[82] The relative prices of natural gas and coal rather than the price of any single fuel drive power sector investment decisions. The projections for relative fuel prices are discussed in Section 4.4.4.

[83] National Petroleum Council. 2011. *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources.* http://www.npc.org/reports/rd.html (see Figure 1.2 on p. 47).

[84] EIA. 2014. U.S. Crude Oil and Natural Gas Proved Reserves, 2013. http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf

generating units. The increases in the natural gas resource base are reflected not only in current natural gas prices and projections (e.g., AEO 2014), but also in current capacity planning by utilities and electricity producers across the country. The North American Electric Reliability Corporation's (NERC) Long Term Reliability Assessment, which is based on utility plans for new capacity over a 10-year period, reinforces this consensus by stating that "gas-fired generation [is] the primary choice for new capacity." [85]

The EPA's and EIA's modeling frameworks are designed to reflect the longer term, fundamentals-based perspective that electric utilities and developers employ in evaluating capital investments, while analyzing alternative scenarios to account for broader fuel market uncertainties. Short-term fuel price volatility is not the most relevant factor in this context because new power plants have asset lives measured in decades, not in months or years, and new capacity investment decisions are based on long-run expected prices, not month-to-month, or even year-to year, variations in fuel prices. Shorter-term prices will affect how units are dispatched, but these potential dispatch impacts are considered with other factors over a longer time horizon and factored into the choice of which type of plant to build. In contrast, the uncertainty surrounding long-term fuel prices will exert significantly greater influence on the technology selected for new capacity additions. In a modeling context with perfect foresight, this longer term uncertainty may be evaluated by the comparisons of alternative scenarios presented throughout this chapter.

In addition to major changes in the gas supply outlook, there have been notable changes in the coal supply outlook. Coal costs have generally increased over the past few years due primarily to increased production costs. These costs have increased as the most accessible and economically viable mines are depleted, requiring movement into coal reserves that are more costly to mine. The basic trends in coal supply are not expected to change for the foreseeable future.[86]

Taken together, current and expected natural gas and coal market trends are contributing to a recent fundamental shift in the economic conditions for new power plant development that utilities and developers have recognized and responded to in planning.[87]

[85] NERC, Long-Term Reliability Assessments for 2012. New capacity includes both planned and conceptual resources as defined by NERC.

[86] http://www.eia.gov/forecasts/aeo/assumptions/pdf/coal.pdf

[87] For example: "We don't have any plans to build new coal plants. So the rules won't have much of an impact. Any additional generation plants we'd build for the next generation will be natural gas." American Electric Power, 3/26/2012, National Journal; "As we look out over the next two decades, we do not plan to build another coal plant. … As the evidence is coming in, [shale gas] is proving to be the real deal. If we have no

4.4.4 Power Sector Fuel Projections

To examine the potential impacts of uncertainty inherent in natural gas and coal markets, the EIA used scenario analysis to generate the 2020 fuel price projections in Table 4-4. The relative prices of available fuels partially drive power sector investment decisions. Even under scenarios where the spread between the unit price of gas and coal is highest, no construction of new non-compliant generating capacity is projected in 2020, as shown in Table 4-3.

Table 4-4. National Delivered 2020 Fuel Prices by AEO 2014 Scenario (2011$/MMBtu)

Scenario	Natural Gas	Coal
Reference	4.99	2.57
High Growth	5.28	2.59
Low Growth	4.97	2.55
High Coal Cost	5.13	2.90
Low Coal Cost	4.88	2.27
High Gas/Oil Resource	4.30	2.45
Low Gas/Oil Resource	5.63	2.63

Note: AEO 2014 scenario definitions: High Economic Growth assumes real GDP growth is 2.8 percent peryear from 2012 to 2040 (base case assumes 2.4 percent); Low Economic Growth assumes real GDP growth is 1.9 percent per year High Coal Cost assumes lower regional productivity growth rates and higher wages, equipment, and transportation costs for the coal industry; Low Coal Cost assumes greater regional productivity growth rates and lower wages, equipment, and transportation costs for the coal industry; High Oil and Gas Resource expands the ultimate estimated recovery of shale gas, tight gas, and tight oil by 100 percent; Low Oil and Gas Resource reduces the ultimate estimated recovery of shale gas, tight gas, and tight oil by 50 percent.

However, given that power plants are long-lived assets, capacity planning decisions are necessarily undertaken with a forward view of expected market and regulatory conditions. In producing the AEO 2014, EIA capacity expansion projections are informed by a lifecycle cost analysis over a 30-year period in which the expectations of future prices are consistent with the projections realized in the model (i.e. the model executes decisions with perfect foresight of future market, technical, and regulatory conditions). Therefore, the fuel prices that inform

plans, as one of the largest utilities and largest users of coal in this country, no plans to build a new coal plant for two decades, the regulations are not relevant.” Jim Rogers (Duke), 3/27/2012, NPR All Things Considered.; “If you actually look at the economics today, you would be burning gas, not coal,” Jack Fusco, Calpine, 12/1/2010, Marketplace; “Coal’s most ardent defenders are in no hurry to build new ones in this environment.” John Rowe, Exelon, 9/2011, EnergyBiz; “With low gas prices, gas-fired generation kind of snowplows everything else” Lew Hay, NextEra, 11/1/2010, Dow Jones. “The Demise of Coal-Fired Power Plants” , Washington Post, Nov 23, 2012 (new EGU construction is natural-gas fired, even in Kentucky coal country).

capacity expansion decisions in 2020 are not only the prices that year, but the entire future fuel price stream. For example, Figure 4-2 displays EIA's natural gas price projections for the Reference Case and several key scenarios through 2050.

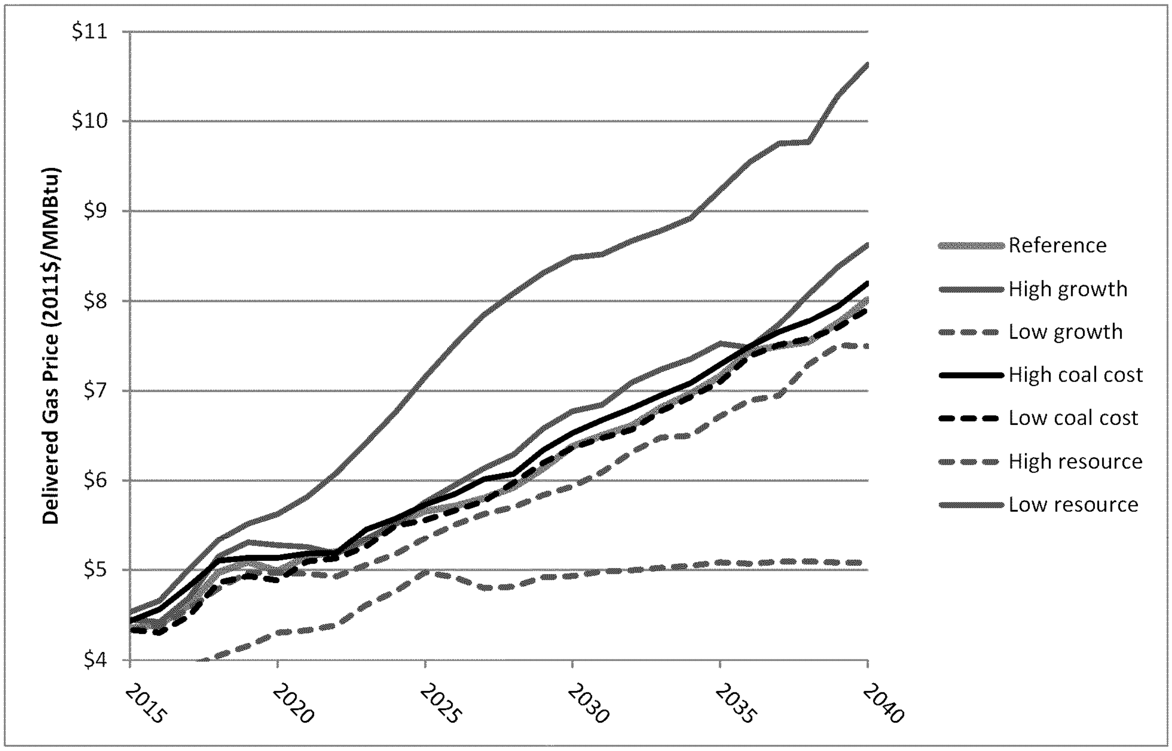


Figure 4-2. National Real Price of Natural Gas Delivered to EGUs for Select AEO 2014 Scenarios (2011$/MMBtu)

Note: The AEO gas price forecasts go through 2040. The AEO forecasted prices are interpolated to 2050 by applying the average annual rate of price increase from 2035 to 2040 in each AEO scenario to all subsequent years from 2041 through 2049.

Natural gas prices are expected to increase after 2020 in all scenarios.[88] However, rising natural gas prices through 2040 – including in EIA's low gas/oil resource scenario - are still not sufficient to support new, non-compliant coal-fired generation through 2022 in these scenarios. This demonstrates that natural gas prices do not have to continue at currently low levels for NGCC to maintain its economic advantage over coal-fired technologies.

While the uniformity of EIA scenarios in projecting no new, non-compliant coal-fired capacity through the analysis period is compelling, the scenario projections cannot fully illustrate the extent of the economic advantage that NGCC maintains over conventional coal,

[88] Coal prices are also expected to rise in all scenarios.

only that the advantage remains intact across a broad range of market and technical scenarios. To identify potential market conditions that could fully erode the cost advantages of NGCC over coal-fired technologies during the analysis period, the unit-level engineering cost analysis in section 5.4 compares these technologies. That analysis builds on the unit-level cost comparisons presented in the following sections of this chapter.

4.5 Levelized Cost of Electricity Analysis

New capacity projections from the EPA and EIA reviewed in the previous section indicate that the NSPS is not projected to require changes in the design or construction of new EGUs from what would be expected in the absence of the rule. Thus, under both the baseline projections and alternative scenarios analyzed in AEO 2014, the final EGU New Source GHG Standards are projected to result in negligible emission reductions, quantified benefits, or costs.

To further examine the robustness of these conclusions the EPA conducted additional analysis using the levelized cost of electricity (LCOE) for different types of new generation technologies. The LCOE is a widely used metric that represents the cost, in dollars per output, of building and operating a generating facility over the entirety of its economic life. Evaluating competitiveness on the basis of the LCOE is particularly useful in establishing cost comparisons between generation types with similar operating characteristics but with different cost and financial characteristics. The typical cost components associated with the LCOE include capital, fixed operating and maintenance (FOM), variable operating and maintenance (VOM), transportation, storage and monitoring (TS&M) and fuel. (See preamble section V. H. 5.)

4.5.1 Overview of the Concept of Levelized Cost of Electricity

The levelized capital and FOM costs may be calculated by taking the annualized capital and FOM (expressed in $/kW-yr) costs and spreading the expense over the annual generation of the facility using the expected average annual capacity factor (the percent of full load at which a unit would produce its actual annual generation if it operated for 8,760 hours). The annualized capital cost (expressed in $/kW-yr) is the product of the $/kW capital cost and the capital recovery factor (CRF). A CRF may be calculated using the project's interest rate and book life.[89]

The VOM cost, which is already expressed in terms of cost per unit output, may be presented with or without the fuel expense. The fuel expense is typically the largest component of VOM costs (non-fuel components to VOM include start-up fuel, consumables,

[89] The interest rate assumed for NGCC and CT projects is 9.06 percent; the interest rate assumed for coal-fired projects is 9.57 percent. All three types of projects are assumed to have a 30-year book life, resulting in a capital recovery factor of 9.78 percent for NGCC and CT projects and 10.23 percent for coal-fired projects.

inspections, etc.) and for certain capacity types – such as NGCC – fuel expense may represent the majority of the LCOE.

Because levelized costs consider the entire lifecycle of the facility, fuel expenses are represented by the levelized fuel price which captures the forecast of annual delivered fuel prices over the economic life of the facility at a given discount rate.[90] Levelizing fuel prices recognizes the necessity to consider the trajectory of fuel costs over the facility's entire economic life.

It should be noted that there are other important considerations beyond the LCOE that impact power plant investment decisions. New power plant developers must consider the particular demand characteristics in any particular region, the existing mix of generators, operational flexibility of different types of generation, prevailing and expected electricity prices, other potential revenue opportunities (e.g., the capacity value of a particular unit, where certain power markets have mechanisms to compensate units for availability to maintain reliability, sale of co-products, etc.), and the varying financial risks associated with different generation technologies. Broader system-wide power sector modeling – such as the analyses conducted by the EPA and EIA – is able to more effectively capture some of these considerations.

4.5.2 Cost and Performance of Technologies

This section reports the LCOE of individual technologies that are affected EGUs of this final rule.[91] These are compared in the following sections.The NGCC and coal-fired generation technology cost and performance assumptions that form the basis for the LCOE analysis in this

[90] As an illustration of applying a discount rate to a stream of future fuel prices, the levelized fuel price will be less than the mean fuel price if prices are increasing, equal to the mean if fuel prices are constant, and greater than the mean if fuel prices are declining. The weighting of nearer-term prices through the application of a discount rate is consistent with modeling economic behavior of investors. The EPA used a 5 percent discount rate to calculate levelized fuel prices, a value consistent with the discount rate embedded in IPM. The model applies a discount rate of 4.77 percent for optimizing the sector's decision-making over time. IPM's discount rate, designed to represent a broad range of private-sector decisions for power generation, rates differs from discount rates used in other analyses in this RIA, such as the benefits analysis which each assume alternative social discount rates of 3 percent and 7 percent. These discount rates represent social rates of time preference, whereas the discount rate in IPM represents an empirically-informed price of raising capital for the power sector. Like all other assumed price inputs in IPM, the EPA uses the best available information from utilities, financial institutions, debt rating agencies, and government statistics as the basis for the capital charge rates and the discount rate used for power sector modeling in IPM.

[91] The LCOE data used in the analyses in this RIA represent slight modifications of the data provided by NETL to reflect fuel prices consistent with AEO. These include using a coal price of $2.52/MMBtu, a natural gas price of $6.19/MMBtu and an IGCC capacity factor of 85 percent (consistent with the SCPC and NGCC capacity factors).

RIA are from the DOE's National Energy Technology Laboratory (NETL).[92] NETL cost and performance characteristics were selected for coal-fired technologies because the NETL estimates were unique in the detail of their cost and performance estimates for a range of CO_2 capture levels for both new super critical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) facilities.[93,94] In particular, the NETL costs released in 2015 include vendor quotes for new technology deployed. The use of NETL cost and performance characteristics also allows for comparisons to be made across generating technologies using a single, internally consistent framework. The CO_2 capture sensitivity analysis included an evaluation of the cost, performance, and environmental profile of these facilities under different configurations that were tailored to achieve a specific level of carbon capture. For simple cycle CTs, NETL cost and performance estimates were not available or sufficiently recent so the EPA adopted EIA's AEO 2014 estimates of the LCOE.

To represent a new SCPC facility, NETL assumed a new boiler with a combination of low-NOx burners with overfire air and a selective catalytic reduction system for NOx control. The plant was assumed to have a fabric filter and a wet limestone flue gas desulfurization scrubber for particulate matter and SO_2 control, respectively. For configurations including CCS, the plant was assumed to have a sodium hydroxide polishing scrubber to ensure that the flue gas entering the CO_2 capture system has a SO_2 concentration of 10 parts per million or less. The SCPC unit treating a slip stream with partial post-combustion CCS were assumed to be equipped with the CO_2 removal system designed by Shell Cansolv, the system currently in full-scale commercial use at the Boundary Dam facility.[95] Estimated costs for the system reflect the latest vendor quotations.

[92] http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf

[93] All potential build types are compliant with all current environmental regulations, including the EPA's MATS.

[94] The NETL cost data intend to represent the next commercial offering, and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs (a challenge for emerging technologies). The cost estimates for plant designs that only contain fully mature technologies which have been widely deployed at commercial scale (e.g., pulverized coal power plants without CO_2 capture) reflect nth-of-a-kind (NOAK) on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to "learning by doing" and risk reduction benefits that result from serial deployments as well as from continuing research and development. The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., IGCC and any plant with CO_2 capture) use the same cost estimating methodology as for the mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that initial deployments of the IGCC and capture plants may incur costs higher than those reflected within this report. Actual reported project costs for all of the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g. contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays, etc.) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

[95] NETL 2015 at 59, 137.

Specific to the partial capture configurations for SCPC, the NETL study identified two options. The first option identified was to process the entire flue gas stream through the capture system, but at reduced solvent circulation rates. The second option was to maintain the same high solvent circulation rate and stripping steam requirement as would be used for full capture, but only treat a portion of the total flue gas stream. The NETL report determined that this "slip stream" approach was the most economical because a reduction in flue gas flow rate would: (1) decrease the quantity of energy consumed by flue gas blowers; (2) reduce the size of the CO_2 absorption columns; and (3) trim the cooling water requirement of the direct contact cooling system.[96] The "slip stream" approach – which leads to lower capital and operating costs – was therefore adopted by the EPA for cost and performance estimates under partial capture. [97][98]The technology cost and performance characteristics utilized by the EPA in developing the LCOE estimates discussed in this chapter and Chapter 5 are listed below in Table 4-5.

Table 4-5. Technology Cost and Performance Specifications (2011$)

Capacity Type	Total Overnight Capital Cost ($/kW)	Fixed Operations & Maintenance ($/kW-yr)	Variable Operations & Maintenance ($/MWh)	TS&M ($/MWh)	Levelized Fuel Cost ($/MMBtu)	Net Plant HHV Efficiency (%)
NGCC	891	26.7	1.8	-	6.19	50.2
SCPC	2,507	71.5	9.1	-	2.52	40.7
SCPC w/ Partial CCS (1,400 lb/MWh gross)	3,042	85.6	10.1	1.4	2.52	39.2
SCPC Co-Firing Natural Gas (1,400 lb/MWh gross)	2,507	71.5	9.6	-	3.77	40.3
IGCC	3,036	96	9.4	-	2.52	39.0
IGCC Co-Firing Natural Gas	3,036	96	9.4	-	2.73	39.0

[96] NETL based this determination primarily upon a review of the literature. See page 2 of http://www.netl.doe.gov/energy-analyses/pubs/Gerdes-08022011.pdf

[97] For additional detail and discussion on the specific technology configurations selected for this analysis, please refer to the preamble.

[98]

(1,400
lb/MWh)

~~Notes: Cost from NETL 2015. The coal assumed is a bituminous coal with a sulfur content of 2.8 percent (dry) at a real (2011$)~~ price of $2.52/MMBtu, consistent with AEO 2014 Reference Case forecast levelized delivered coal (all types) price. The natural gas price is the EIA AEO 2014 forecast levelized real (2011$) delivered gas price from EIA's AEO 2014 Reference Case. NETL (2015) explains that there are a range of future potential costs that are up to 15 percent below, or 30 percent above their central estimate, consistent with a "feasibility study" level of design engineering applied to the various cases in this study. The value of the studies lie not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

4.5.3 Levelized Cost of Electricity of New Generation Technologies

To support and provide context for the sectoral modeling results presented above, this section presents two LCOE comparisons:[99]

1. NGCC to non-compliant Coal – to demonstrate the cost advantages of NGCC across a range of natural gas prices and regional market conditions.
2. NGCC to CT – to demonstrate the low likelihood of a new combustion turbine being built with the expectation of meeting the applicability criteria based on utilization and thus being covered by these standards.

The illustrative unit cost and performance characteristics used in this section assume representative costs associated with spatially dependent components, such as connecting to existing fuel delivery infrastructure and the transmission grid. In practice units may experience higher or lower costs for these components depending on where they are located. It should be noted that the LCOE comparisons presented in this section only represent the cost to the generator and do not reflect the additional social costs that are associated with emissions of greenhouse gases or other air pollutants. A broader consideration of the health and welfare (i.e., non-health benefits) impacts of emissions from these technologies is considered in Chapter 5.

It is also important to note that both the EIA and the EPA apply a climate uncertainty adder (CUA) - represented by a three percent increase to the weighted average cost of capital –

[99] As the sectoral modeling may not capture all considerations, particularly local ones, under which a non-compliant coal unit may be built, Section 5.5 provides a comparison of the cost of a non-compliant coal unit to a compliant coal unit, either with partial CCS or natural gas co-firing. The analysis demonstrates that the standard could be accommodated and would not, based on the cost increment of constructing and operating a CCS, preclude new coal construction. The section also demonstrates how the cost to a non-compliant coal unit of complying with the final standard is mitigated by the emission reduction benefits of controlling its emissions.

to new, conventional coal-fired capacity types.[100] EIA developed the CUA to address inconsistencies between power sector modeling absent GHG regulation and the widespread use of a cost of CO_2 emissions in power sector resource planning. While baseline power sector modeling scenarios may not specify potential future GHG regulatory requirements, investors in the industry typically incorporate some expectation of a future cost to limit CO_2 emissions in resource planning evaluations that influence investment decisions. Therefore, the CUA reflects the additional planning cost typically assigned by project developers and utilities to GHG-intensive projects in a context of climate uncertainty. The EPA believes the inclusion of the CUA in LCOE estimates is consistent with the industry's current planning and evaluation framework for future projects (demonstrable through IRPs and public utility commission orders) and is therefore pertinent when evaluating the cost competitiveness of alternative generating technologies.[101]

In defining the CUA, EIA states that "the adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility they may eventually have to purchase allowances or invest in other GHG emission-reducing projects that offset their emissions."[102] Therefore, the EPA recognizes the application of the CUA is context dependent. As a part of the planning process, it is appropriately applied to evaluating prospective projects, and then removed once a project transitions from planning to execution. While omitting the CUA is inconsistent with an analysis considering how project characteristics and market conditions would lead a developer or utility to select a certain project, as is the purpose of this section, for transparency the cost estimates based on the 2015 NETL analysis for non-compliant coal-fired projects are presented in the following analysis both with and without the CUA. All LCOE estimates of coal-fired facilities with CCS are presented without the CUA, to represent the reduced CO_2 liability associated with such technologies.

4.5.4 Levelized Cost of Electricity of NGCC and Non-compliant Coal

The EPA's base LCOE estimates for NGCC, SCPC, and IGCC are shown in Figure 4-3 by cost component (capital, FOM, VOM, TS&M, and fuel) and assume a construction date of 2020

[100] While this statement is true in the AEO Reference Case, EIA evaluates No GHG Concern where the CUA is removed. Results from this scenario on investment in new technology are reported in Table 4-3.

[101] For example, a 2011 Synapse Report lists 15 utilities that adopted a value for estimating CO_2 emissions liability in their integrated resource planning. http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf. In addition to utilities, several state commissions have mandated the inclusion of potential financial liabilities associated with CO_2 emissions in long-term planning (e.g., Minnesota utilities must adopt a price beginning in 2017).

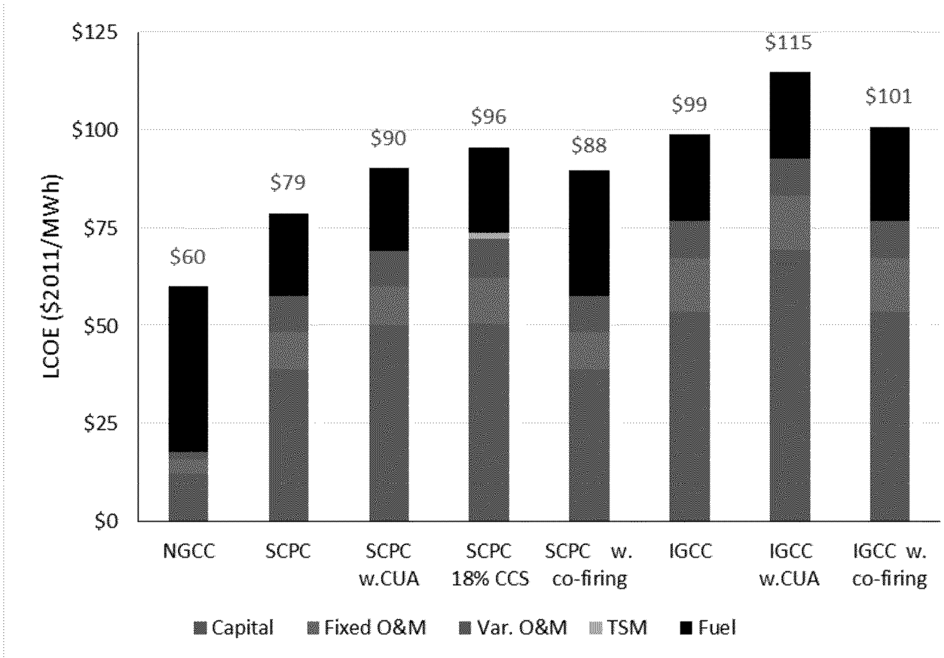
[102] http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

and an 85 percent capacity factor. Although the EPA believes that this cost data is broadly representative of the economics between new coal and new natural gas facilities, this analysis assumes representative new units and does not reflect the full array of new generating sources that could potentially be built. To the extent that other types of new EGUs that would be affected by this rule are built, they may exhibit different costs than those presented here. For example, new conventional coal facilities of a size smaller than what is assumed in the base estimate would tend to exhibit a relatively higher LCOE, while some technologies could potentially display a lower LCOE if, all else equal, fuel could be obtained at a lower price than that assumed in this analysis (such as may be the case for petroleum coke or waste coal facilities). These potential differences do not fundamentally change the analysis presented in this RIA.

On a levelized cost basis, NGCC is significantly cheaper than all of the non-compliant coal-fired options. For technologies that are included in the IPM Base Case and the AEO, their LCOE values are comparable to the LCOE values calculated from the NETL study. The difference in the LCOE of NGCC and non-compliant coal technologies explains the finding in the sectoral modeling described above that natural gas generation is forecast to be the source of new fossil-fired generation.

In addition to the disparity in total LCOE, there are fundamental differences in the cost composition between natural gas- and coal-fired facilities. NGCC costs are dominated by fuel expense while the levelized cost of coal-fired technologies driven by capital expense. Consequently, this section will explore the impact of changes in natural gas price and the capital costs of coal-fired facilities to better quantify the magnitude of the relative cost advantage NGCC exhibits over coal-fired alternatives.

Figure 4-3. Illustrative Wholesale Levelized Cost of Electricity of Alternative New Generation Technologies by Cost Component



Notes:

(1) The coal assumed is a bituminous coal with a sulfur content of 2.8 percent (dry) and a real delivered price of $2.52/MMBtu. $2.52/MMBtu is the levelized real (2011$) delivered average coal price from the AEO 2014 reference case for all coals during the 20 year forecast period 2020-2039. The $2.52/MMBtu coal price is assumed for all years; therefore, the price serves as both the 2020 fuel cost as well as the levelized fuel cost over any future period of time.

(2) The levelized delivered price of natural gas is $6.19/MMBtu (2011$).

(3) SCPC and IGCC without CCS are shown first without any CUA and then with a 3 percent CUA.

(4) The cost of CO_2 transport, storage and monitoring (TS&M) is included as part of LCOE for SCPC with 18 percent CCS, which captures and sells CO_2.

(5) A capacity factor of 85 percent is assumed across all technologies.

(6) For comparison, EIA estimates of levelized costs in 2019 under AEO 2014 Reference Case assumptions for SCPC and IGCC are $94.4/MWh and $114.7/MWh (both in 2012$), respectively, including a 3 percent CUA and excluding transmission investment costs.[103] The levelized costs presented above are based on NETL assumptions and will necessarily differ from AEO 2014 levelized costs for a variety of reasons, including cost and performance characteristics, financial assumptions, and fuel input prices.

Figure 4-4 presents the LCOE of an NGCC facility at four alternative levelized natural gas price levels. For comparison, the LCOE estimates for SCPC and IGCC (with no CO_2 control) including the CUA are provided as well.[104]

[103] http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

[104] Some new units could be designed to combust waste coal or petroleum coke (pet coke), which may be affected by this rule. These technologies could exhibit different local economics, particularly in the delivered price of fuel. From a capital and operating perspective, the EPA believes the cost and performance of these units are broadly similar and therefore well represented by new, conventional coal-fired facilities (e.g. SCPC).

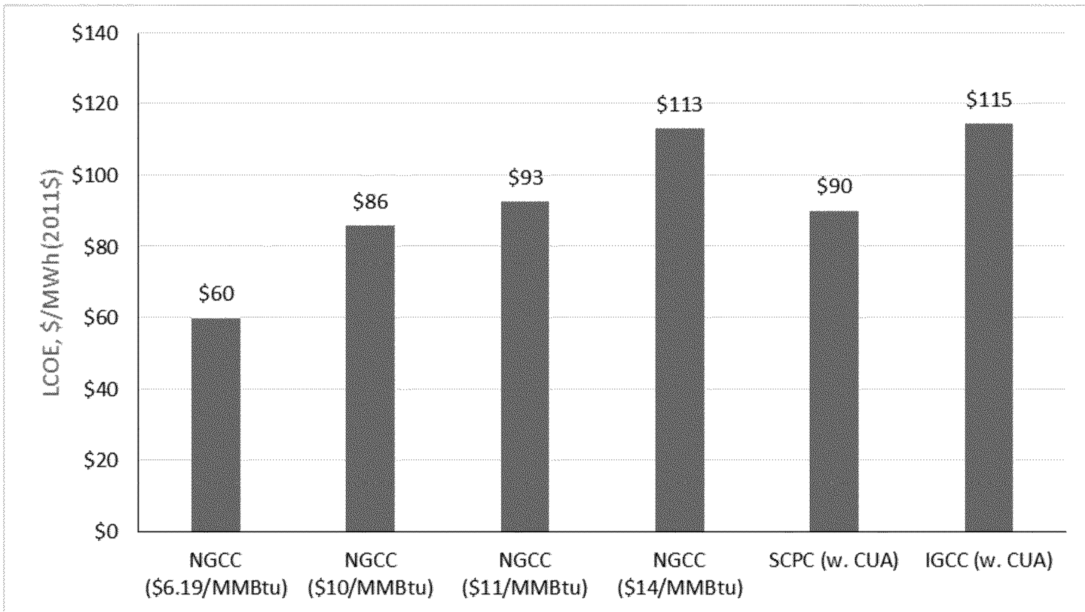


Figure 4-4. Illustrative Wholesale Levelized Cost of Electricity of Alternative New Generation Technologies Across Alternative Natural Gas Prices

It is only when natural gas prices exceed $10/MMBtu on a levelized basis (in 2011$) that new coal-fired generation without CCS approaches parity with NGCC in terms of the LCOE. None of the AEO 2014 scenarios described in this chapter project national average natural gas prices near that level.[105] To achieve a $10/MMBtu levelized price in 2020 would require a significantly more pessimistic natural gas outlook than what is contained in AEO's low natural gas resource scenario. To illustrate, Table 4-6 report the levelized natural gas prices (initial year of 2020) for both a 20-year period (to accommodate the end of EIA's modeling projections in 2040) and 30-year period (calculated by continuing the projected level of price increases through 2050).

Table 4-6. Levelized Natural Gas Prices by Select AEO 2014 Scenario (2011$/MMBtu)

Scenario	20-Year AEO Projection (2020-2039)	30-Year AEO-Based Projection (2020-2049)
Reference	6.07	6.53

[105] As noted earlier in this chapter, investment decisions require consideration of fuel price projections over long periods of time; similarly, the power sector modeling cited here make fuel price projections over long periods of time. Neither these modeling projections nor these LCOE calculations are meant to suggest that the gas price could not reach as high as $10/MMBtu at any given point in time, but these analyses do not expect such a price level to be sustained over a period of time that would influence an economic assessment of which type of new capacity offers a better investment.

High Growth	6.32	6.96
Low Growth	5.78	6.20
High Coal Cost	6.19	6.69
Low Coal Cost	6.03	6.47
High Gas/Oil Resource	4.80	4.85
Low Gas/Oil Resource	7.70	8.45

Note: Discount rate of 5 percent, consistent with IPM assumptions. The 30-year natural gas price is calculated by applying the average annual rate of price increase from 2035 to 2040 in all subsequent years from 2041 through 2049. The scenarios are described in Table 4-4.

One potential price path that would achieve a $10/MMBtu on a 20-year levelized basis in 2020 is a natural gas price path 30 percent higher than EIA's low resource scenario in all years (see Figure 4-5). This illustrative price path to achieve a $10/MMBtu levelized price would result in a $11.02/MMBtu annual real price in 2030 and a $13.81/MMBtu real price in 2040. What this information indicates is that natural gas price forecasts need to be notably higher than the highest forecast in the AEO 2014 scenarios before we would expect that general market dynamics would favor new non-compliant coal generation over new compliant natural gas generation as the fossil-fuel technology of choice to satisfy demand. Chapter 5 discusses this finding further by bringing in the consideration of the emissions damages associated with these technologies.

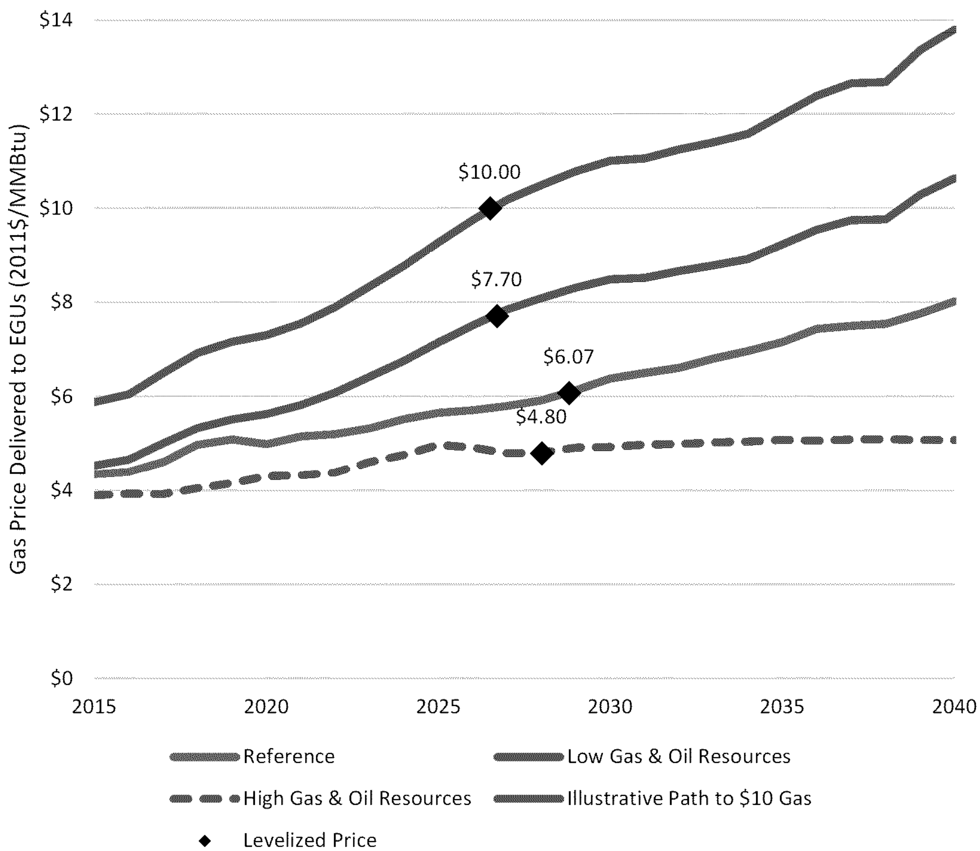


Figure 4-5. Projected Real National Delivered Natural Gas Price for Select AEO 2014 Scenarios and Illustrative Path for > $10/MMBtu Levelized Price

It is important to note that the LCOE calculations are based on assumptions regarding the representative national cost of generation at new facilities.[106] It is known that there is significant spatial variation in the costs of new generation due to design differences, labor productivity and wage differences, and delivered fuel prices, among other potential factors. For example, EIA utilizes capital cost scalars to capture regional differences in labor, material and construction costs.[107] The minimum and maximum capital cost scalars across all regions in AEO

[106] Actual reported project costs for all of the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g. contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays, etc.) that may make construction more costly. Such variations are not captured by the reported cost uncertainty

[107] http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

2014 for SCPC, IGCC, and NGCC build options are presented in Table 4-7.[108]

Table 4-7. AEO 2014 Regional Capital Cost Scalars by Capacity Type

Capacity Type	Minimum Capital Cost Scalar	Maximum Capital Cost Scalar
SCPC	0.885	1.152
IGCC	0.908	1.136
NGCC	0.893	1.205

Applying the regional capital cost scalars displayed above to the base LCOE estimates from NETL developed earlier in this section produces only a small change in the relative competitiveness of the technologies as seen in Table 4-8.

Table 4-8. LCOE Estimates with Minimum and Maximum AEO 2014 Regional Capital Cost Scalars (2011$/MWh)

Capacity Type	Reference LCOE	LCOE Using Minimum Capital Cost Scalar	LCOE Using Maximum Capital Cost Scalar
SCPC (no CCS, without CUA)	79	70	91
SCPC (no CCS, with CUA)	90	80	104
IGCC (no CCS, without CUA)	99	90	112
IGCC (no CCS, with CUA)	115	104	131
NGCC	60	54	72

The LCOE of SCPC in the lowest capital cost region still results in an LCOE that is 11 percent higher than an NGCC located in the most expensive capital cost region when including the CUA. The IGCC LCOE is 25 percent above NGCC in the most expensive region, even without considering the CUA.

The other primary driver in determining the regional impact on competitiveness of new build options is delivered fuel prices. As part of the AEO, EIA releases electric power projections – including fuel prices – for each of the 22 Electricity Market Module (EMM) regions. The two regions with the highest projected 2020 natural gas prices in the AEO 2014 are the Western Electricity Coordinating Council/Southwest (Southwest) and the Florida Reliability Coordinating Council (FRCC). The 20-year levelized natural gas and coal price forecasts (2020-2039) in the AEO 2014 reference case are displayed in Figure 4-6 for both regions.

[108] Excluding the New York City and Long Island areas, as well as those areas of the country that prohibit the development of new, non-compliant coal-fired facilities.

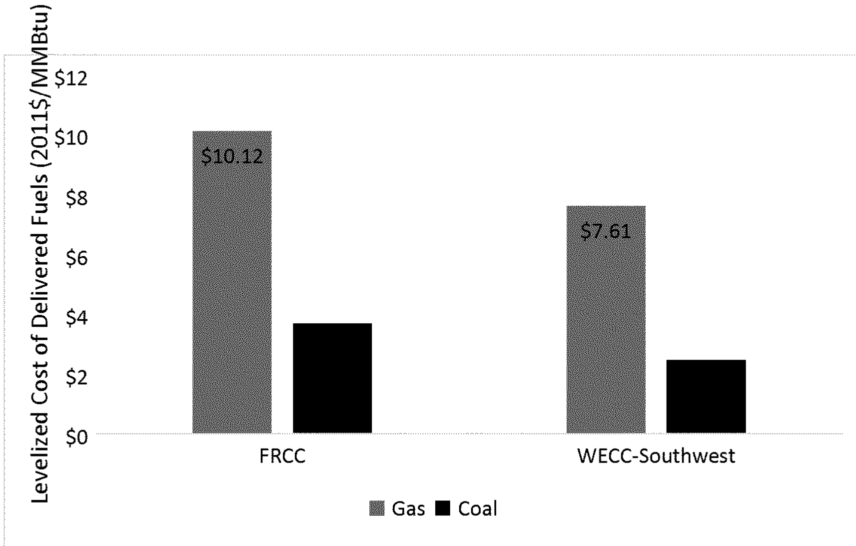


Figure 4-6. Levelized Regional Fuel Price from AEO 2014 Reference Case, 2020-2039 (2011$/MMBtu)[109]

While the FRCC region experiences the highest overall natural gas prices, the Southwest region realizes a greater unit price differential between coal and natural gas prices under the AEO projections. The impact on the LCOE of the SCPC, IGCC, and NGCC technologies without CCS is reported in Table 4-9 for both sets of fuel prices, as well as the national average for comparison.

Table 4-9. LCOE Estimates For Minimum and Maximum AEO 2014 Regional Fuel Prices (2011$/MWh)

Capacity Type	LCOE Using National Average Fuel Prices	LCOE Using FRCC Fuel Prices	LCOE Using Southwest Fuel Prices
SCPC (no CCS, without CUA)	79	89	78
SCPC (no CCS, with 3% CUA)	90	100	90
IGCC (no CCS, without CUA)	99	109	98
IGCC (no CCS, with 3% CUA)	115	125	114
NGCC	60	87	70

Due to the greater fuel price differential, the more favorable region for the development of coal-fired facilities from an LCOE perspective is the Southwest, where the regional fuel prices reduce the LCOE advantage of NGCC to $28/MWh over SCPC (compared with a $32/MWh advantage with national fuel prices) and $23/MWh over IGCC (compared with a $37/MWh advantage with national fuel prices.

[109] Assuming 5 percent discount rate.

In conclusion, even the most favorable combination of regional variability in capital costs and delivered fuel prices represented by EIA are insufficient to support new, unplanned, conventional coal-fired capacity in the analysis period.

4.5.5 Levelized Cost of Simple Cycle Combustion Turbine and Natural Gas Combined Cycle

Simple cycle combustion turbines (CTs) fulfill a fundamentally different function in power sector operations than that of NGCC and fossil-fired steam facilities. CTs are designed to start quickly in order to meet demand for electricity during peak operating periods and are generally less expensive to build on a capital cost basis, but are also less fuel efficient than combined cycle technology, which employs heat recovery systems. Due to lower fuel efficiencies, CTs produce a significantly higher cost of electricity (cost per kWh) at higher capacity factors and consequently are typically utilized at levels below the applicability requirements for EGUs affected by the EGU New Source GHG Standards. New CTs are expected to most often be built to ensure reserve margins are met during peak periods (typically in the summer), and in some instances be able to generate additional revenues by selling capacity into power markets. Thus, in practice, the EPA expects that potential CT units would not meet the applicability requirements finalized in this rule and would therefore, not be subject to the standards of performance.

To illustrate the economic incentives of utilizing combustion turbines in an intermediate and base load mode of operation, Figure 4-7 presents the LCOE estimates for a new conventional CT, Advanced CT and NGCC at increasing capacity factors. The estimates utilize the AEO 2014 Reference Case levelized natural gas price for 2020.

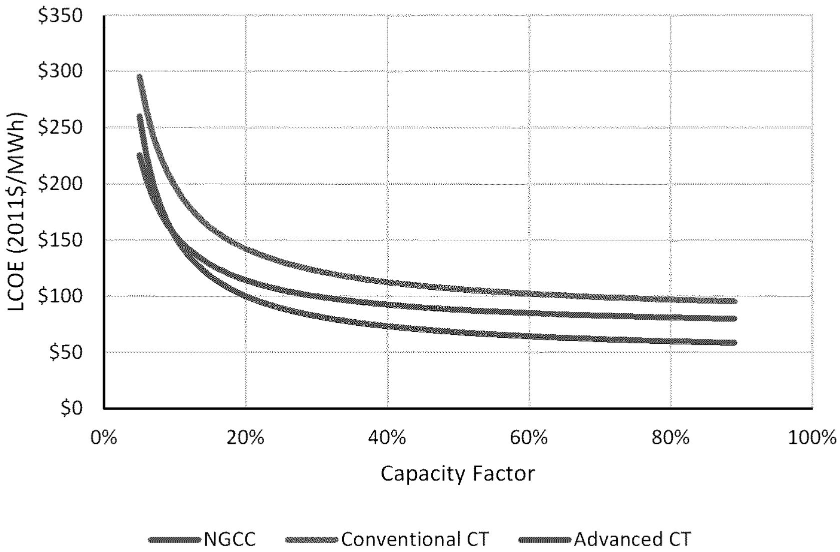


Figure 4-7. Levelized Cost of Electricity Across a Range of Capacity Factors, CT and NGCC (2011$/MWh at $6.07/MMBtu Levelized Natural Gas Price)

In the LCOE figure above, utilizing a CT for generation is less expensive than an NGCC unit only at capacity factors of less than 20 percent.[110] If expected utilization is greater than 20 percent, it can reasonably be expected that a utility or developer would seek to deploy NGCC over CT for a host of economic, environmental, and technical reasons. Furthermore, the design net efficiencies for currently available potentially impacted aeroderivative simple cycle combustion turbines range from approximately 32 percent for smaller designs to 39 percent for the largest intercooled designs. The efficiencies of industrial frame units range from 30 percent for smaller designs to 36 percent for the largest units.[111] The EPA therefore does not expect new CT units to be constructed that would meet the applicability requirements.

4.6 Macroeconomic and Employment Impacts[112]

These final EGU New Source GHG Standards are anticipated to result in negligible emission changes in the electricity sector in the analysis period, and therefore are anticipated to impose negligible costs or quantified benefits. The EPA typically analyzes impacts on employment or labor markets associated with rules based on the estimated compliance costs

[110] CT cost, performance, and financial assumptions from AEO 2013.

[111] These efficiency values follow the methodology the EPA has historically used and are based on the higher heating value (HHV) of the fuel.

[112] The employment analysis in this RIA is part of the EPA's ongoing effort to "conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]" pursuant to CAA section 321(a).

and other energy impacts (e.g., changes in electricity prices), which serve as an input to such analyses. However, since the EPA does not forecast a change in behavior relative to the baseline in response to this rule, there are no notable macroeconomic or employment impacts expected as a result of this rule.

4.7 References

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CHAPTER 5
ANALYSIS OF ILLUSTRATIVE BENEFIT-COST SCENARIOS FOR NEW SOURCES

5.1 Synopsis

The previous chapter of this regulatory impact analysis (RIA) presents the U.S. Environmental Protection Agency's (EPA) analysis and projections from the U.S. Energy Information Administration (EIA) that support the conclusion that the EGU New Source Standards[113] will result in negligible costs and benefits in the period of analysis. The EPA recognizes that this conclusion is based on underlying expected economic conditions (e.g., fuel prices) and assumptions about considerations investors would weigh in deciding whether to build new non-compliant coal-fired power plants. Extending the analysis in the previous chapter that considers those factors in evaluating the robustness of the findings from the sectoral perspective, this chapter presents the results of several illustrative analyses that show, under a range of alternative conditions, the potential costs and benefits of these standards for individual investments that provide base load dispatchable generation. We evaluate conditions under which different generator types are constructed in lieu of a non-compliant supercritical coal unit and estimate the social benefit of adopting the investment that is compliant with the standards. This also allows us to consider the costs and benefits of a situation where an operator chooses to build a new coal-fired unit that is compliant with the standard.

While the analysis in Chapter 4 focuses on national level conditions, the analysis in this chapter explores the potential impacts to individual investments. The analysis in this chapter finds that under unlikely conditions in which the EPA's conclusions regarding the future economic competitiveness of new non-compliant coal-fired units relative to other new generation technologies no longer apply, or in specific situations where an operator chooses to build a coal-fired unit, that the quantifiable benefits of the standards to society outweigh the costs under a range of assumptions.

5.2 Comparison of Emissions from Generation Technologies

As discussed in Chapter 4, natural gas combined cycle (NGCC) units are on average expected to be more economical to build and operate than new coal units (see section 4.5). Therefore, as our point of departure for comparing the costs and benefits of an individual investment decision, we evaluate the private cost of a new NGCC unit that is compliant with the finalized standards with the private cost of a new, non-compliant conventional supercritical

[113] The standards for modified and reconstructed sources are addressed in Chapter 6.

pulverized coal (SCPC) coal-fired unit.[114] When evaluating the costs and benefits associated with these standards, it is also important to understand the difference in emissions associated with these units. In addition to being more economical, new NGCC units have lower emission profiles for CO_2 and criteria air pollutants than new coal units. For example, a typical new SCPC facility that burns bituminous coal in compliance with current utility regulations (e.g., the Mercury and Air Toxics Standards (MATS)) would have considerably greater CO_2, sulfur dioxide (SO_2), nitrogen dioxide (NO_x), toxic metals, acid gases, and particulate emissions than a comparable NGCC facility.

Table 5-1 shows that emissions of these pollutants from a typical new NGCC unit are significantly lower than those from a new coal-fired unit.[115] The emission characteristics are based on, and thus consistent with, the cost and performance assumptions of the illustrative units described in the levelized cost of electricity (LCOE) analysis in section 4.5. That is, these are base load units of the same net capacity operating at an 85 percent capacity factor, the coal unit is assumed to be using bituminous coal with a sulfur content of 2.8 percent dry, they are in compliance with current utility regulations (e.g., the MATS), etc. The typical new NGCC unit would emit about 1.9 fewer million tons of CO_2 per year than the typical new SCPC unit, as well as roughly 1,700 fewer tons of SO_2 and about 1,300 fewer tons of NO_x per year than the SCPC unit. Table 5-1 also provides comparable information for a representative integrated gasification combined cycle (IGCC) unit providing the same amount of electricity and using the same coal. The new IGCC unit would emit less CO_2, SO_2 and NO_x than a typical coal-fired SCPC unit, but has higher emissions of each of these pollutants than a new NGCC unit. Reductions in SO_2 emissions are a particularly significant driver for monetized health benefits, as SO_2 is a precursor to the formation of particulates in the atmosphere, and particulates are associated with premature death and other serious health effects. NO_X is both an ozone precursor, and is associated with formation of secondary fine nitrate $PM_{2.5}$. Both ozone and fine nitrate $PM_{2.5}$ are associated with significant adverse health effects, including premature mortality. Further information on these pollutants' health and welfare effects is described in Chapter 3.

Table 5-1 also shows the representative coal units' emissions of these same pollutants when meeting the promulgated standard of performance of 1,400 lb CO_2/MWh. Two compliant SCPC units are presented: one uses carbon capture and storage (CCS) and another that co-fires

[114] As discussed in section 4.4.1 and in the preamble, we expect new NGCC capacity built in the period of analysis will be compliant with the standard even in the absence of the standard. As a result, there are no compliance costs anticipated for new NGCC units.

[115] Estimated emissions of CO_2, SO_2, and NO_X for the illustrative new coal and NGCC units could vary depending on a variety of assumptions including heat rate, fuel type, and emission controls, amongst others.

natural gas. The compliant IGCC unit is assumed to co-fire natural gas. For the compliant SCPC unit using CCS, in addition to reductions of CO_2, SO_2 emissions would also decrease due to the need to scrub acid gases to very low levels prior to carbon capture in order to prevent degradation of the solvent involved in the capture process.[116] The NO_X emission rate, measured on a net-basis, is slightly lower for non-compliant units than both compliant SCPC units. This is because there is a fuel efficiency loss associated with both compliance technologies and because NO_X emission rate standards for new sources are on a gross-basis. While we account for these increases in the NO_X emission rate in the analysis below, in some cases, NO_X emissions from fossil-fired sources are also subject to mass limits on the total NO_X emissions across EGUs (e.g. in states subject to the Cross-State Air Pollution Rule annual NO_X program), so these emissions may be offset by NO_X reductions from other generating units.

[116] See NETL 2015 at 161.

Table 5-1. Illustrative Emissions Profiles, New Coal and Natural Gas-Fired Generating Units

	Natural Gas CC		SCPC		SCPC+Partial CCS (1,400 lb/MWh Gross)		SCPC+Co-Fire Nat Gas		IGCC		IGCC+Co-Fire Nat Gas	
	Emissions	Emission Rate	Emissions	Emission Rate	Emissions	Emission Rate	Emissions	Emission Rate	Emissions	Emission Rate	Emissions	Emission Rate
SO_2	84	0.0041	1,500	0.71	1,200	0.61	1,500	0.71	18	0.0087	18	0.0087
NO_x	130	0.061	1,500	0.74	1,500	0.75	1,500	0.74	1,100	0.52	1,100	0.52
CO_2	1.6 million	800	3.5 million	1,700	3.1 million	1,500	3.0 million	1,500	3.5 million	1,700	3.4 million	1,700

Notes: Emissions from NETL 2015. Emissions are in short tons/year and Emission Rates are in net lb/MWh. Values rounded to two significant digits. Emission characteristics are based on, and thus consistent with the cost and performance assumptions of, the illustrative units described in LCOE analysis in section 4.5 (i.e., these are base load units running at 85 percent capacity factor, all coal units are assumed to be using bituminous coal with a sulfur content of 2.8 percent dry, etc.). The tons of emissions are estimated for a coal-fired facility that achieves the gross-output standard of 1,400 lb/MWh and presented in this table on a net output basis. For the post-combustion CCS system assumed in the SCPC case, acidic gases (e.g., SO_2, HCl) need to be scrubbed to very low levels prior to going to the CCS system to avoid degradation of the solvent. Therefore, SO_2 emissions are lower in the case of the SCPC unit with partial CCS. See preamble for discussion about the format of the standard. Here we further assume all units are of the same capacity (600 MW net).

5.3 Comparison of Health and Climate Impacts from Generation Technologies

As discussed in the previous section, the emissions of GHGs and other pollutants associated with new sources of electricity generation are greater for coal-fired units than for NGCC units. Reducing the emissions associated with electricity generation results in climate, human health, and non-health benefits.

To consider the health and climate benefits associated with the adoption of lower emitting new generation technologies, we apply the 2022 social benefit values discussed in Chapter 3 to the differences in illustrative emission profiles between the technologies in Table 5-1.[117] Specifically, we multiply the difference in CO_2 emissions between two technologies by the estimates of the social cost of carbon dioxide (SC-CO_2) (Table 3-1), multiply the difference in SO_2 and NO_X emissions by the $PM_{2.5}$-related SO_2 and NO_X benefit per ton (BPT) estimates (Table 3-2), and add those values to get a measure of the 2022 social benefits attributable to differences in emissions of adopting the lower emitting new generation technology. We subsequently divide by the amount of generation (in MWh) underlying the annual emissions estimates to derive the social benefits attributable to the differences in emissions per unit of generation.

Only the direct emissions of CO_2, SO_2, and NO_X are considered in this illustrative exercise. Other air and water pollutants emitted by these technologies and emissions from the extraction and transport of the fuels used by these technologies are not considered. For example, coal has higher mercury emissions than natural gas, but the relative benefits from the difference in mercury emissions are not considered. A similar example of emissions not considered are those of directly emitted $PM_{2.5}$. Furthermore, there may be differences in upstream greenhouse gas emissions (in particular, methane) from different technologies which were not quantified for this assessment.

Table 5-2 reports the 2022 incremental climate and health benefits associated with a new NGCC unit relative to a new coal-fired SCPC and IGCC units, given different mortality risk studies and assumptions about the discount rate. These benefits are based on the emissions presented in Table 5-1. The benefits presented in Table 5-2 are estimated on an output basis to enable easier comparisons to the potential costs of investing in a new non-compliant coal-fired unit relative to a new NGCC unit. These incremental benefits should be relatively invariant

[117] Due to data limitations, we are not able to estimate annualized benefits from the stream of emissions over the lifetime of the generating technologies. Because the benefit per-ton of emission reductions increases over time, due in part to population growth, the single year estimate results in a conservative comparison of benefits to costs where LCOE represents annualized lifetime costs of generating technologies.

across natural gas prices and other economic factors. Depending on the discount rate and mortality risk study used, 2022 incremental benefits associated with generation from a representative new NGCC unit relative to a new coal-fired SCPC or IGCC unit are $7.0 to $91 per MWh (2011$).[118]

The health and welfare benefits associated with reduced emissions can depend on a number of factors, including the specific fuels combusted and the location of the emissions. While the benefits of reduced CO_2 emissions do not depend on the location of generation because the location of CO_2 emissions does not influence their impact on the evolution of global climate conditions, the precise incremental health co-benefits will be location specific and depend on the specific fuels used. However, these factors will not change the qualitative conclusion. There will be incremental climate and human health benefits associated with a new NGCC unit relative to a new coal-fired unit, independent of the location.

[118] Different discount rates are applied to SC-CO_2 than to the other benefit estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. Moreover, several rates are applied to SC-CO_2 because the literature shows that it is sensitive to assumptions about discount rate and because no consensus exists on the appropriate rate to use in an intergenerational context. The SC-CO_2 interagency working group centered its attention on the 3 percent discount rate but emphasized the importance of considering all four SC-CO_2 estimates. See the 2010 SC-CO_2 TSD. Docket ID EPA-HQ-OAR-2009-0472-114577 or http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf for details.

Table 5-2. Incremental Benefits ($/MWh, 2011$) of Emission Reductions from Illustrative New Natural Gas Combined Cycle Generation *Relative to* New Non-Compliant SCPC or IGCC Coal Generation in 2022[119]

	SCPC	IGCC
CO_2-Related Benefits using SC-CO_2		
5% Discount Rate	$5.7	$5.8
3% Discount Rate	$19	$19
2.5% Discount Rate	$28	$28
3% Discount Rate (95th percentile)	$56	$57
Total $PM_{2.5}$-Related Co-Benefits from SO_2 and NO_X Changes		
3% discount rate		
Krewski et al. (2009)	$15	$1.3
Lepeule et al. (2012)	$34	$3.0
7% discount rate		
Krewski et al. (2009)	$14	$1.2
Lepeule et al. (2012)	$31	$2.7

Combined CO_2-Related and $PM_{2.5}$-Related Benefits

	Discount Rate Applied to $PM_{2.5}$-Related Benefits (range based on adult mortality function)			
SC-CO_2 Discount Rate	3%	7%	3%	7%
5% Discount Rate	$21 to $40	$19 to $37	$7.1 to $8.8	$7.0 to $8.5
3% Discount Rate	$34 to $53	$33 to $50	$20 to $22	$20 to $22
2.5% Discount Rate	$43 to $62	$42 to $59	$30 to $31	$30 to $31
3% Discount Rate (95th percentile)	$72 to $91	$70 to $87	$59 to $60	$58 to $60

Notes: The emission rates and operating characteristics of the units being compared in this table are reported in Table 5.1. Benefits are estimated for a 2022 analysis year. The range of benefits within each SC-CO_2 value and discount rate for $PM_{2.5}$-related benefits pairing reflects the use of two core estimates of $PM_{2.5}$-related premature mortality.[120] The EPA has evaluated the range of potential impacts per MWh by combining all SC-CO_2 values with health benefits values at the 3 percent and 7 percent discount rates. Combining the 3 percent SC-CO_2 values with the 3 percent health benefit values assumes that there is no difference in discount rates between intragenerational and intergenerational impacts. $PM_{2.5}$-related co-benefits are estimated using 2020 monetized health benefits-per-ton of $PM_{2.5}$ precursor reductions (Table 3-2), which are representative of 2022.

[119] This analysis assumes representative new units and does not reflect the full array of new generating sources that could potentially be built (e.g., a comparison of a small new conventional coal-fired unit with a small natural gas-fired unit, or a comparison of a waste coal or petroleum coke-fired unit to a natural gas-fired unit of a comparable size and capacity factor). However, the damages associated with other units that could be built, and which would be subject to this rule, would not change noticeably (i.e., these new facilities would be subject to emissions standards for other pollutants and would emit similar levels of SO_2, NO_X, and CO_2, on an output basis) except for differences in location, as discussed previously.

[120] The range of estimated benefits for each discount rate is due to the EPA's use of two alternative primary estimates of $PM_{2.5}$-related mortality impacts: a lower primary estimate based on Krewski et al. (2009) and a higher primary estimate based on Lepeule et al. (2012).

The conclusion from this analysis is that there are significant environmental and health benefits associated with electricity generation from a representative new NGCC unit relative to a new non-compliant coal-fired unit. Other studies of the social costs of coal and natural gas-fired generation provide similar findings (Muller et. al., 2011; NRC, 2009).[121]

As explained previously, the power sector has moved away from the construction of coal-fired power plants in favor of natural gas-fired power plants due, in part, to the significant cost differential. Even so, it is possible that a limited number of currently unplanned coal-fired power plants would be constructed through 2022. In these circumstances, the construction of compliant coal-fired units in place of non-compliant coal-fired units would result in relative climate and human health and non-health benefits. Table 5-3 reports the 2022 incremental benefits associated with a new SCPC coal-fired unit with CCS relative to a new SCPC coal-fired unit, given different mortality risk studies and assumptions about the discount rate. The values are calculated based on the emissions presented in Table 5-1. Depending on the discount rate used and mortality risk study used, 2022 incremental benefits associated with generation from a representative new SCPC coal-fired unit with CCS relative to a new SCPC unit without CCS are \$3.1 to \$18 per MWh (2011\$), factoring in the disbenefit from a small increase in NO_x emissions.[122] These incremental benefits will be referenced in the analyses presented in subsequent sections.

Table 5-3. Incremental Benefits (\$/MWh, 2011\$) of Emission Reductions from Compliant Coal-Fired Generation with CCS meeting 1,400 lb/MWh Standard Relative to New Non-Compliant Coal-Fired Generation in 2022

	SCPC

[121] Muller et al. 2011 conclude that, "coal-fired power plants have air pollution damages larger than their value added", while the same is not true for natural gas plants (see Table 5 in Muller et al.). However, these comparisons are based on typical existing coal and natural gas units, including natural gas boilers, and are not sensitive to location (although the underlying analysis in the study does account for differences in the location of existing units when estimating damages). The NRC 2009 study shows that only the most polluting natural gas units may cause greater damages than even the least polluting existing coal plants (compare Tables 2-9 and 2-15 in NRC 2009). However, the NRC comparison does not compare new units located in the same place, and so some of the natural gas units with the greatest damages may be attributable to their location, and includes natural gas steam boilers, which have a higher emission rates per unit of generation than NGCC units. Despite these caveats, the finding of these two studies are consistent with the findings in this section.

[122] Different discount rates are applied to SC-CO_2 than to the other benefit estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. Moreover, several rates are applied to SC-CO_2 because the literature shows that it is sensitive to assumptions about discount rate and because no consensus exists on the appropriate rate to use in an intergenerational context. The SC-CO_2 interagency group centered its attention on the 3 percent discount rate but emphasized the importance of considering all four SC-CO_2 estimates. See the 2010 SC-CO_2 TSD for details. Docket ID EPA-HQ-OAR-2009-0472-114577 or http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.

CO_2-Related Benefits using SC-CO_2		
5% Discount Rate	$1.3	
3% Discount Rate	$4.4	
2.5% Discount Rate	$6.6	
3% Discount Rate (95th percentile)	$13	
Total PM2.5-Related Benefits from SO_2 and NO_X Changes		
3% discount rate		
Krewski et al. (2009)	$1.9	
Lepeule et al. (2012)	$4.3	
7% discount rate		
Krewski et al. (2009)	$1.7	
Lepeule et al. (2012)	$3.9	
Combined CO_2-Related and $PM_{2.5}$-Related Benefits		
	Discount Rate Applied to $PM_{2.5}$-Related Benefits (range based on adult mortality function)	
SC-CO_2 Discount Rate	3%	7%
5% Discount Rate	$3.2 to $5.6	$3.1 to $5.2
3% Discount Rate	$6.3 to $8.7	$6.1 to $8.3
2.5% Discount Rate	$8.5 to $11	$8.3 to $10
3% Discount Rate (95th percentile)	$15 to $18	$15 to $17

Notes: Benefits are estimated for a 2022 analysis year. The range of benefits within each SC-CO_2 value and discount rate for $PM_{2.5}$-related benefits pairing reflects the use of two core estimates of $PM_{2.5}$-related premature mortality.[123] The EPA has evaluated the range of potential impacts per MWh by combining all SC-CO_2 values with health benefits values at the 3 percent and 7 percent discount rates. Combining the 3 percent SC-CO_2 values with the 3 percent health benefit values assumes that there is no difference in discount rates between intragenerational and intergenerational impacts. $PM_{2.5}$-related co-benefits are estimated using 2020 monetized health benefits-per-ton of $PM_{2.5}$ precursor reductions (Table 3-2), which are representative of 2022.

[123] The range of estimated benefits for each discount rate is due to the EPA's use of two alternative primary estimates of $PM_{2.5}$-related mortality impacts: a lower primary estimate based on Krewski et al. (2009) and a higher primary estimate based on Lepeule et al. (2012).

[124] Different discount rates are applied to SC-CO_2 than to the other benefit estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. Moreover, several rates are applied to SC-CO_2

Table 5-4 reports the 2022 incremental benefits associated with a new compliant coal-fired unit co-firing natural gas relative to a new non-compliant coal-fired unit, given different mortality risk studies and assumptions about the discount rate. The values are calculated based on the emissions presented in Table 5-1. Depending on whether the unit is SCPC or IGCC, the discount rate used, and mortality risk study used, 2022 incremental benefits associated with generation from a representative new coal-fired unit co-firing natural gas relative to a new coal-fired unit that does not co-fire natural gas are 0.25 to $14 per MWh (2011$).[124] These incremental benefits will be used in the analyses presented in subsequent sections.

Table 5-4. Incremental Benefits ($/MWh, 2011$) of Emission Reductions from Compliant Coal-Fired Generation with Co-Firing Natural Gas Relative to New Non-Compliant Coal-Fired Generation in 2022

	SCPC Co-Firing Natural Gas	IGCC Co-Firing Natural Gas
CO_2-Related Benefits using SC-CO_2		
5% Discount Rate	$1.5	$0.25
3% Discount Rate	$4.8	$0.82
2.5% Discount Rate	$7.2	$1.2
3% Discount Rate (95th percentile)	$14	$2.5
Total $PM_{2.5}$-Related Benefits from SO_2 and NO_X Changes		
3% discount rate		
Krewski et al. (2009)	-	-
Lepeule et al. (2012)	-	-
7% discount rate		
Krewski et al. (2009)	-	-
Lepeule et al. (2012)	-	-

Combined CO_2-Related and $PM_{2.5}$-Related Benefits	Discount Rate Applied to $PM_{2.5}$-Related Benefits (range based on adult mortality function)			
SC-CO_2 Discount Rate	3%	7%	3%	7%
5% Discount Rate	$1.5	$1.5	$0.25	$0.25
3% Discount Rate	$4.8	$4.8	$0.82	$0.82
2.5% Discount Rate	$7.2	$7.2	$1.2	$1.2
3% Discount Rate (95th percentile)	$14	$14	$2.5	$2.5

because the literature shows that it is sensitive to assumptions about discount rate and because no consensus exists on the appropriate rate to use in an intergenerational context. The SC-CO_2 interagency group centered its attention on the 3 percent discount rate but emphasized the importance of considering all four SC-CO_2 estimates. See the 2010 SC-CO_2 TSD for details. Docket ID EPA-HQ-OAR-2009-0472-114577 or http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.

Notes: Benefits are estimated for a 2022 analysis year. The range of benefits within each SC-CO_2 value and discount rate for $PM_{2.5}$-related benefits pairing reflects the use of two core estimates of $PM_{2.5}$-related premature mortality.[125] The EPA has evaluated the range of potential impacts per MWh by combining all SC-CO_2 values with health benefits values at the 3 percent and 7 percent discount rates. Combining the 3 percent SC-CO_2 values with the 3 percent health benefit values assumes that there is no difference in discount rates between intragenerational and intergenerational impacts. $PM_{2.5}$-related co-benefits are estimated using 2020 monetized health benefits-per-ton of $PM_{2.5}$ precursor reductions (Table 3-2), which are representative of 2022.

5.4 Illustrative Analysis – Benefits and Costs of New Source Standards across a Range of Gas Prices

As the analysis in Chapter 4 demonstrated, under a wide range of likely electricity market conditions – including the EPA base case and EIA reference case scenarios as well as multiple alternative scenarios – it is expected that the industry will choose to construct new units that already meet the standards of this rulemaking in the baseline. Section 4.5.4 further explored how much higher natural gas prices would need to be to favor new non-compliant coal generation over new NGCC generation. In this section, we continue that analysis by considering the potential impacts of the regulation on benefits if key assumptions regarding natural gas prices were to change during the analysis period. The analysis in this section indicates that in this scenario, the standards for new sources would result in increased private costs, but would also lead to climate and human health benefits, and is highly likely to provide net benefits to society as a whole. [126]

Furthermore, this section, as in section 4.5.4, demonstrates that local fuel prices must be significantly different than regional differences already captured in IPM and EIA's modeling of private investment costs to favor the construction of a new non-compliant coal-fired unit over a new NGCC unit to serve a particular load. Section 4.5.4 describes how regional conditions and other factors may influence the LCOE comparison, and how these regional differences are already captured in the electricity sector modeling in support of this rule. The 64 different regions in IPM reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs).[127] However, there may be local conditions within those regions which differ meaningfully from the broader regional conditions.

[125] The range of estimated benefits for each discount rate is due to the EPA's use of two alternative primary estimates of $PM_{2.5}$-related mortality impacts: a lower primary estimate based on Krewski et al. (2009) and a higher primary estimate based on Lepeule et al. (2012).

[126] EO 13563 states that each agency must "propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits are hard to quantify)." While the presence of net social benefits for a given regulatory option is not the only condition necessary for optimal regulatory design, it does signify that the regulatory option is welfare improving for society.

[127] Further disaggregation of the NERC assessment regions and RTOs allows a more accurate characterization of the operation of the U.S. power markets by providing the ability to represent transmission bottlenecks across RTOs and ISOs, as well as key transmission limits within them.

The analysis in this section evaluates how substantially divergent those local conditions must be from representative conditions for non-compliant coal generation to be the fossil fuel-fired technology of choice to serve demand.

The starting point for this analysis is the illustrative comparison (presented in Section 4.5) of the relative LCOE of representative new coal-fired SCPC and IGCC EGUs and representative NGCC units.[128] That comparison demonstrated a significant difference in the LCOE between the coal-fired and natural gas-fired generating technologies. The estimated LCOE for a representative NGCC unit is roughly $30 and $39 per MWh less than for a representative new coal-fired SCPC or IGCC unit, respectively (see Figure 4-3).[129] This is consistent with the EPA's expectation that the new source standards for steam units are not projected to impose any appreciable costs or quantified benefits under current and likely future market conditions, as discussed in Chapter 4. The emissions associated with these technologies, and the benefits in terms of reduced damages of operating the new NGCC unit in lieu of the new non-compliant coal unit, are reported in the previous section.

To supplement this conclusion, this section identifies three relevant ranges within the distribution of future natural gas prices that can be classified as likely gas prices, unexpectedly high natural gas prices, and unprecedented natural gas prices. Because the cost of natural gas is a significant share of the LCOE for NGCC units, we evaluate how changes in natural gas prices affect differences in the relative private costs of new technologies. We identify the natural gas price when the private costs, which are inclusive of the CUA for the SCPC, suggest that a new non-compliant coal unit may be adopted by an investor in lieu of a new NGCC unit. We then compare the social costs of these technologies, which is inclusive of both the private costs of these technologies and the damages from these technologies but exclusive of the CUA, at this natural gas price.[130] We then identify the natural gas price when the social cost of investing in

[128] By fixing generation in this comparison, we are assuming that both technologies generate the same benefits in the form of electricity generating services. We assume in the discussion that the benefit of electricity production to consumers outweighs the private and social investment cost. However, a caveat of our comparison is that at particularly high fuel prices this might not be the case (that is, at high costs for both technologies, it may not be worthwhile to construct either technology). For a discussion of when comparing the levelized costs of different generating technologies provides informative results and when it does not see, for example, Joskow 2010 and 2011.

[129] The reported decrease in the LCOE from adopting NGCC are relative to the SCPC with 3 percent carbon uncertainty adder (CUA) and IGCC without 3 percent CUA. The CUA is described in Chapter 4.

[130] When forecasting the behavior of private actors in choosing between different technologies based on expected future costs, we account for a CUA, but when comparing the difference in costs of illustrative new units after construction, such as in the analysis of the social costs of these technologies (i.e., the private cost plus the cost associated with their emissions), the CUA is not included. The CUA is described in section 4.5.3. The private cost of these technologies may differ from the social cost of these technologies for reasons other than their

the new non-compliant coal unit is plausibly less than the social cost of the new NGCC unit.

In general, this analysis shows that there would likely be a net social benefit, even under scenarios with higher than expected gas prices, if new compliant NGCC units were built in place of new non-compliant coal-fired units as a result of this rule.[131] Under some conditions, higher natural gas prices may result in a net social cost of constructing and operating new natural gas in lieu of non-compliant coal, holding all other parameters constant and disregarding social benefits that we are unable to monetize.[132] However, even under these unlikely conditions these finalized standards may yield social net benefits as there may be other technologies to serve demand that would have a lower social cost than a new non-compliant coal unit.

5.4.1 Likely Natural Gas Prices

As shown in Chapter 4, it is only when natural gas prices exceed $10/MMBtu on a levelized basis (in 2011 dollars) that the representative new non-compliant SCPC unit likely becomes competitive with new NGCC in terms of its cost of electricity produced. As discussed in Chapter 4, none of the AEO2014 scenarios approach this natural gas price level on either a forward looking 20-year levelized price basis or on an average annual price basis at any point during the analysis period.[133]

5.4.2 Unexpectedly High Natural Gas Prices

At natural gas prices above $10/MMBtu, the private LCOE for a new SCPC unit may fall

associated emissions, as described at the end of Section 5.5.

[131] As previously noted, the benefits estimated in this section are based on a single year (2022) of emissions from different generating technologies. Due to data limitations, we are not able to estimate annualized benefits from the stream of emissions over the lifetime of the generating technologies. This results in a conservative comparison of benefits to costs where LCOE represents annualized lifetime costs of generating technologies.

[132] As described below, an outcome where there are net social costs is unlikely to occur over our analysis period and for a significant period beyond. However, even a situation where natural gas prices are significantly higher, such as very high economic growth, would increase both natural gas and coal prices at the same time - making it harder to alter the underlying cost advantage of NGCC generation. Furthermore, even in the situation where we report net social costs, it is important to recall that the analysis is limited in the types of benefits and costs considered, given that it does not account for the emissions associated with the production and delivery of natural gas and coal, the limitations of current SC-CO_2 estimates, and the limited accounting of non-CO_2 emissions benefits. As previously discussed, the current SC-CO_2 estimates do not capture all important all of the physical, ecological, and economic impacts of climate change recognized in the climate change literature. Despite our attempts to quantify and monetize as many of the co-benefits as possible, the health and welfare co-benefits are not fully quantified or monetized in this assessment. For more information about unquantified health and welfare co-benefits please refer to tables 5-2 and 6-2 of the PM NAAQS RIA (U.S. EPA, 2012), respectively.

[133] As reported in Table 4-6, The projected delivered electricity sector natural gas price for 2020 assuming a 5 percent discount rate in the AEO 2014 reference scenario is $6.53/MMBtu (2011$). In the “Low oil and gas resource” it is $8.45/MMBtu (2011$).

below that of a new NGCC unit.[134] Therefore, in the event of such unexpectedly high levelized fuel prices, some new SCPC units might be constructed in the absence of this final rulemaking, provided that coal price do not rise at the same time, there is sufficient demand for electricity, and new non-compliant SCPC units are competitive with other new and existing generating technologies other than NGCC units. In this scenario, we expect some compliance costs if a new NGCC unit (or a compliant coal-fired unit) were to be built in lieu of the non-compliant coal unit. However, generation from a new NGCC unit would also have incremental environmental and health benefits as it emits less CO_2 SO_2, and NO_x than generation from a new non-compliant SCPC unit (as may a compliant coal-fired unit; see Section 5.5).

For levelized natural gas prices of $10/MMBtu and somewhat higher, the resulting emission reduction benefits of building an NGCC unit, rather than a non-compliant SCPC unit, will outweigh the increase in costs of an NGCC unit over a non-compliant SCPC unit. This observation indicates that the standard for new fossil steam sources would yield net benefits in the analysis year. For example, at a levelized gas price of $11/MMBtu, the NGCC unit would generate electricity for approximately $14/MWh more than the non-complaint SCPC unit on a levelized basis,[135] and result in incremental benefits from emissions reductions of $19 to $91/MWh (see analysis of 2022 relative benefits of NGCC: Table 5-2). The net benefit of this scenario would be $5.6 to $77/MWh.

For context, a natural gas price of $10/MMBtu (in 2011 dollars) is higher than any national average annual natural gas price faced by the electric power sector since at least 1996, when the EIA historic data series begins.[136] The continued development of unconventional natural gas resources in the U.S. suggests that annual gas prices may actually tend to be towards the lower end of the historical range. In addition, the highest projected average levelized natural gas price for 2020 of any of the AEO 2014 scenarios cited in Chapter 4 is $8.45/MMBtu (2011$), which occurs in the Low Oil and Gas Resource scenario (see Table 4-6). As discussed in Chapter 4, none of the EIA sensitivity cases (which account for future fuel prices for both gas and coal) show scenarios where non-compliant coal-fired units become more economic than NGCC units in the period of analysis.

5.4.3 Unprecedented Natural Gas Prices

At extremely high natural gas prices, the LCOE for a non-compliant SCPC unit could be

[134] As noted above, the private LCOE of the non-compliant SCPC unit is inclusive of the CUA.

[135] The LCOE of the representative NGCC unit increases by $6.80/MWh for every $1/MMBtu increase in natural gas prices.

[136] See: http://www.eia.gov/dnav/ng/hist/n3045us3A.htm. EIA reports average annual delivered natural gas prices to the electricity sector for the past 16 years (since 1997).

sufficiently lower than the cost of a new NGCC unit, such that the net benefit of the new fossil steam standard in a given year could be negative (i.e., a net cost), at least under some ranges of benefit estimates. For example, at a very high[137] levelized gas price of $14/MMBtu, the NGCC unit would generate electricity for roughly $34/MWh more than the illustrative non-compliant SCPC, but result in social benefits from lower emissions of $19 to $91/MWh relative to the non-compliant SCPC unit (see analysis of 2022 relative benefits of NGCC: Table 5-2). If the NGCC unit were built in lieu of the SCPC unit as a result of the new fossil steam standard, the impact would range from a net social cost of $15/MWh to a net social benefit of $56/MWh relative to the SCPC unit.

Depending on which discount rates are used to estimate benefits, it is possible that the standard would result in a net cost (i.e., costs exceed benefits). However, as noted in the previous subsection, natural gas prices at these levels would be unprecedented. As a result, the EPA believes that the probability of levelized natural gas prices reaching levels at which this standard would generate net social costs is extremely small.

We emphasize that differences in generating costs, plant design, local factors, and the relative differences between fuels costs can all affect the precise circumstances under which the new steam fossil standard would be projected to have no costs, net social benefits or net social costs. However, based on historical and expected gas prices, we project that the new fossil steam standard is most likely to have negligible costs because firms will invest in technology that will comply with the standard in the baseline, and, if it does result in costs, it is also likely to produce positive, although modest, net social benefits. Furthermore, these results, complemented by the analysis in Chapter 4 on regional differences in levelized costs of these technologies, indicate that local differences in the cost of these technologies must be significantly different from representative conditions for non-compliant coal generation to be the technology of choice to serve demand. Therefore the probability that this finalized standard would result in net social costs is exceedingly low.

5.5 Illustrative Analysis – Benefits and Costs of Non-Compliant Coal and Compliant Coal

As discussed in detail in the previous section and in Chapter 4, it is unlikely that a new non-compliant coal-fired unit would be constructed in the analysis period. The power sector continues to move away from the construction of coal-fired power plants in favor of natural gas-fired power plants due, in part, to the significant LCOE differential explored in the previous

[137] For context, between 2009 and 2014 the national annual average nominal price of natural gas delivered for electricity generation ranged from $3.58/MMBtu to $5.30/MMBtu. The 6 year average was $4.76/MMBtu, roughly 1/3 the illustrative high price of $14/MMBtu.

section. Even so, an operator may have reasons to choose to construct a conventional coal-fired power plant. (For example, some comments received on the 2012 and 2014 proposed regulations suggested that an operator may find it desirable to construct a new coal-fired EGU for the purpose of diversifying its generation fleet across fuels to hedge against uncertainty in fuel markets.) In these circumstances, the EPA believes that any need for CCS could be accommodated and would not, based on the incremental cost of the CCS portion of the new unit, preclude the construction of the new coal-fired facility. One factor in determining that needing CCS would not preclude the construction of the new facility is the availability of Enhanced Oil Recovery (EOR) opportunities for new coal-fired facilities.[138]

This section evaluates the impacts that might occur if an investor, which otherwise wanted to construct a new non-compliant coal unit, chose to instead construct a new compliant coal-fired unit in response to the new fossil steam standard. In this scenario, this decision would result in some costs in order to build a unit with partial CCS or co-fire with natural gas.[139] However, there would also be climate and other benefits resulting from changes in CO_2 and SO_2.

For each coal-fired generation type, SCPC and IGCC, the EPA analyzed the cost of constructing these units and emission impacts of meeting the new source standards in 2022. While partial CCS is considered the best system of emission reductions (BSER) for these SCPC units, it would also be possible to meet the standard without CCS through co-firing natural gas, which is also analyzed.

The cost of CCS used to support this rule assumes that the geologic sequestration of CO_2 will be in deep saline formations and accounts for the cost of doing so, but the EPA also recognizes the potential for sequestering CO_2 for EOR. For non-EOR applications, transportation, storage, and monitoring (TS&M) costs of \$5-\$15 dollars per ton of CO_2 are applied based on the level of capture. This range is consistent with estimates provided by NETL and the Global CCS Institute.[140]

[138] The potential availability of EOR was not used in the EPA's evaluating the reasonableness of cost in determining the best system of emissions reduction (BSER).

[139] In this section we do not include a CUA for the illustrative new non-compliant SCPC and IGCC units as we are assuming that the investor will install construct and operate a new coal fired plant regardless. Furthermore, as in the previous section, when comparing the difference in costs of illustrative new units after construction, such as in the analysis of the social costs of these technologies (i.e., the private cost plus the cost associated with their emissions), the CUA is not included.

[140] http://www.netl.doe.gov/energy-analyses/pubs/QGESS_CO2T%26S_Rev2_20130408.pdf http://www.globalccsinstitute.com/publications/economic-assessment-carbon-capture-and-storage-technologies-2011-update.

Note that NETL assumes 100 kilometers (62 miles) of pipeline, but points out that, of the 500 largest existing CO_2

EOR refers to the injection of gases and/or fluids into a reservoir to increase oil production efficiency. CO_2-EOR has been successfully used at many production fields throughout the United States. The oil and natural gas industry in the United States has over 40 years of experience in injection and monitoring of CO_2. This experience provides a strong foundation for the technologies used in the deployment of CCS on coal-fired electric generating units. Although deep saline formations provide the most CO_2 storage opportunity (at least 2,243 billion tons), oil and gas reservoirs are estimated to have 228 billion tons of CO_2 storage resource.[141]

The use of CO_2 for EOR can significantly lower the cost of implementing CCS. The opportunity to sell the captured CO_2 rather than paying directly for its long-term storage, greatly improves the economics of the new generating unit. According to the International Energy Agency, of the CCS projects in operation (e.g., Boundary Dam Energy Project, Saskatchewan, Canada) or under construction or at an advanced stage of planning, 70 percent intend to use captured CO_2 to improve recovery of oil in mature fields, including Mississippi Power's Kemper County Energy Facility, NRG Energy's W.A. Parish Petra Nova CCS Project, Summit Power's Texas Clean Energy Project, and the Hydrogen Energy California Project. The Texas Clean Energy project is planning to capture 90 percent of the CO_2 and sell it for EOR.[142]

Therefore, in the near term, new coal-fired EGUs with CCS may be located in areas amenable to using the captured CO_2 in EOR operations because these formations have been previously well characterized for hydrocarbon recovery, likely already have suitable infrastructure (e.g., wells, pipelines, etc.), and have an associated economic benefit of increasing oil well productivity. Furthermore, the EPA believes the opportunity to engage in EOR opportunities is not significantly limited by the location of those opportunities or the current CO_2 pipeline infrastructure (12 states currently have active EOR operations). Provision of electric power does not require coal-fired facilities to be co-located with the demand it is intended to serve. Please refer to Chapter 2 for a more detailed discussion of EOR, including its geographic availability, expected future growth, and overall impact on the economics of CCS.

There are two EOR opportunities evaluated in this section – 'High' and 'Low.' The high EOR opportunity assumes a CO_2 sale price of $36 per ton; the low EOR opportunity assumes a CO_2 sale price of $18 per ton based on assumptions used by NETL in evaluating potential EOR

point sources, 95 percent are located within 100 kilometers (62 miles) miles of a potential geologic storage reservoir. Therefore it is reasonable to assume that a new source can be similarly located.

[141] U.S. Department of Energy National Energy Technology Laboratory (2012). United States Carbon Utilization and Storage Atlas, Fourth Edition.

[142] http://www.texascleanenergyproject.com/

opportunities.[143] For either opportunity, it is assumed that the facility is only responsible for the costs of transmitting the captured CO_2 to the fence line, as is currently the practice.[144] Costs for TS&M of CO_2, however, are real costs that must be borne by someone. Whether the facility, the pipeline owner or the eventual user (i.e., oil field producer) of the CO_2 bear the TS&M cost could be negotiated, with the outcome varying in different situations. We expect that when CO_2 is sold for EOR applications, the buyer rather than the EGU operator will likely bear those costs. However, for the purposes of this analysis, the TS&M costs are included for both EOR and non-EOR applications, recognizing that this likely slightly overstates the cost to the operator in circumstances where CO_2 is sold for EOR.

Figure 5-1 compares the LCOE for a non-compliant coal to a compliant coal unit with partial CCS both with and without EOR. With the exception of the LCOE costs accounting for EOR, these costs were provided in Table 4-5. We see in Figure 5-1 that if a limited number of non-compliant coal-fired power plants would have been constructed in the analysis period the adoption of CCS could be accommodated and would not, based on the incremental cost of the CCS portion of the new unit, preclude the construction of the new coal-fired facility. Furthermore, Figure 5-1 shows the LCOE analysis estimate that a non-compliant coal unit could achieve a 1,400 lb/MWh emission rate by co-firing with 34 percent natural gas (at a levelized cost of $3.77/MMBtu) at an SCPC unit, or with 6 percent natural gas at an IGCC unit.

[143] The High and Low CO_2 sale prices utilized by the EPA are consistent with NETL's Base Case and Low Case sale prices, respectively (http://www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf). In addition, this range is broadly consistent with the CO2 sale price data collected by the Department of Interior for projects located on federal lands (http://statistics.onrr.gov/ReportTool.aspx). Prices are expressed in 2011$ and the price is expected to be static over time. Prices were converted from metric to short tons using a factor of 0.90718474.

[144] For EOR applications the point of sale is typically the facility fence line, in which case the coal facility operator will avoid the TS&M cost. Consequently, the economic benefit of EOR to the investor in the coal plant may be greater than simply the price paid for CO_2.

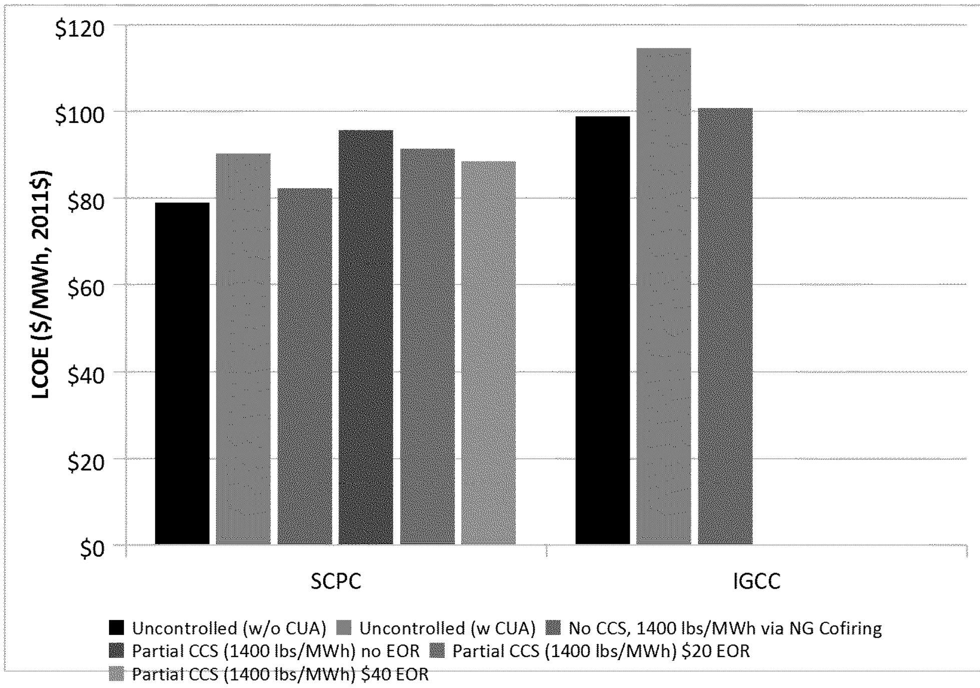

Figure 5-1. Levelized Cost of Electricity, Uncontrolled Coal and Coal with Partial CCS (1,400 lb/MWh gross). 2011$

Notes:

(1) Cost data from NETL 2015, adjusted for EOR revenue and co-firing where applicable.

(2) A non-compliant 550 MW (net capacity) unit SCPC requires NG co-firing at 34% to achieve a 1,400 lb/MWh CO_2 emission rate. A non-compliant 620 MW (net) IGCC unit requires 6 percent NG co-firing. LCOE costs for co-firing were estimated assuming a levelized $6.19/MMBtu price of delivered gas.

(3) The partial control alternatives that achieve 1,400 lb/MWh using CCS without EOR include the cost of TS&M.

Tables 5-5 and 5-6 show the costs and 2022 net-benefits (social benefits minus private compliance costs) per MWh of adopting compliant coal in lieu of non-compliant coal. The EPA estimates of the benefits or disbenefits associated with changes in CO_2, SO_2, and NO_X emissions using the methods described in Table 5-3. The cost estimates used are reported in Figure 5-1. As before, it is important to note that these comparisons omit additional benefits that may be associated with the abatement of greenhouse gas emissions and other benefits associated with reducing criteria pollutant emissions.

Table 5-5. Illustrative 2022 Costs and Benefits for Compliant SCPC with Partial Capture or with Co-Firing Natural Gas Relative to Non-Compliant SCPC (per MWh 2011$)

	SCPC with Partial CCS	SCPC Co-Firing Natural Gas
Additional LCOE [a]	$17	$9.4
Revenue from EOR (Low - High EOR)	$4.2 to $7.1	*
Additional LCOE, net of EOR	$9.6 to $13	*
Value of Monetized Benefits for 2022 Emissions		
SC-CO_2 5% with Krewski 3% to SC-CO_2 3% (95th) with Lepeule 3%[b]	$3.2 to $18	$1.5 to $14
Net Monetized Benefits		
Without EOR Revenue	-$13 to $0.84	-$7.9 to $5.1
With EOR Revenue	-$9.3 to $7.9	*

[a] For this comparison the LCOE of the representative SCPC without CCS or co-firing natural gas does not include 3 percent CUA.

[b] Benefits are estimated for a 2022 analysis year. Values shown are calculated using different discount rates. Four estimates (average SC-CO_2 at discount rates of 5, 3, and 2.5 percent, respectively, and 95th percentile SC-CO_2 at 3 percent) of the SC-CO_2 in the year 2022 were used. See Table 3-1 for the SC-CO2 estimates. =The average SC-CO_2 at 5 percent produced the lowest estimate and the 95th percentile estimate at 3 percent produced the highest estimate. See section 3.2 for complete discussion of these estimates. $PM_{2.5}$-related co-benefits are estimated using 2020 monetized health benefits-per-ton of $PM_{2.5}$ precursor reductions (Table 3-2), which are representative of 2022.

Table 5-6. Illustrative 2022 Costs and Benefits for Compliant IGCC with Co-Firing Natural Gas Relative to Non-Compliant IGCC (per MWh 2011$)

	IGCC Co-Firing Natural Gas
Additional LCOE[a]	$1.9
Revenue from EOR (Low - High EOR)	*
Additional LCOE, net of EOR	*
Value of Monetized Benefits for 2022 Emissions	
SC-CO_2 5% with Krewski 3% to SC-CO_2 3% (95th) with Lepeule 3%[b]	$0.25 to $2.5
Net Monetized Benefits	
Without EOR Revenue	$-1.7 to $0.55
With EOR Revenue	*

[a] For this comparison the LCOE of the representative IGCC co-firing natural gas does not include 3 percent CUA.
[b] Benefits are estimated for a 2022 analysis year. Values shown are calculated using different discount rates. Four estimates (average SC-CO_2 at discount rates of 5, 3, and 2.5 percent, respectively, and 95th percentile SC-CO_2 at 3 percent) of the SC-CO_2 in the year 2022 were used. See Table 3-1 for the SC-CO2 estimates. =The average SC-CO_2 at 5 percent produced the lowest estimate and the 95th percentile estimate at 3 percent produced the highest estimate. See Section 3.2 for complete discussion of these estimates. $PM_{2.5}$-related co-benefits are estimated using 2020 monetized health benefits-per-ton of $PM_{2.5}$ precursor reductions (Table 3-2), which are representative of 2022.

As shown in Chapter 4, current market conditions indicate that a unit compliant with the standards is currently the most economical investment, even in the baseline. The costs reported in Tables 5-5 and 5-6 represent the compliance costs to a hypothetical investor who, in the baseline, would choose to build a non-compliant fossil-fired steam power plant and, in compliance with the standard, still constructs the plant but now in such a way that reduces the plant's emissions. In short, the compliance costs are the expenditures that the investor would make in order to comply with the standard. The underlying premise of this example is that the profit from the plant exceeds the additional cost of compliance to the investor; otherwise the investor would not be expected to make the investment. If the profit were less than the compliance costs then the investor's lost profits would be the private costs. For this reason, if the investor makes a different compliance decision other than those assumed in Table 5-5 and 5-6 the private costs will be lower, and therefore, the compliance costs presented in Table 5-5 and 5-6 would be an upper bound to the private costs borne by the hypothetical investor.

As explained in OMB's Circular A4 and the EPA's Guidelines for Economic Analysis, social costs, and not private costs, are the appropriate metric for the benefit-cost analysis in this RIA. Social costs represents the total burden that a regulation or action will impose on the economy. It is defined as the sum of all opportunity costs incurred as a result of a regulation or action where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed as a result of a regulation. The opportunity cost of a regulation or activity is measured by the prices of the goods and services used in response to the regulation or required for that activity. Therefore, when a resource is used in response to a regulation or for an activity, it has a social cost associated with it.

The costs in Tables 5-5 and 5-6 could be taken to approximate the social cost of an individual investor complying with the standard, assuming that investor would chose to construct a compliant fossil-fired steam power plant rather than making an alternative investment. However, detailed behavioral models of the electricity sector (such as IPM) that take into many of the important criteria for investment decisions over time show that this investment decision does not hold across the economy. Therefore, these estimates are unlikely to be representative of the social costs of this rule. The conclusions presented in Chapter 4 – that costs of the rule are likely to be negligible – represent the best approximation of the overall cost to society.

5.6 Impact of the New Source Standards Considering the Cost of Lost Option Value

Consistent with the EPA's practice in evaluating the benefits and costs of significant rules, Chapter 4 uses detailed electricity sector modeling of expected market conditions to demonstrate that new EGUs expected to be built in the period of analysis would be in compliance with this final rule, even in the absence of this rule. As a result in the analysis period, as measured in those deterministic settings, the cost are expected to be negligible and there are no quantified benefits. That analysis is extended in this chapter to consider unexpected conditions in which the construction of a new non-compliant coal-fired unit would be desirable from the perspective of an individual investor and evaluates the costs and social benefits of constructing a generating technology that complies with the final rule instead. This section further extends, and draws on, those analyses to discuss, qualitatively, the potential social benefits and costs of the standards from the perspective of an uncertain future.

Firms operating in the power sector have a set of options available to address increases in electricity demand, such as increasing the utilization of existing generating capacity, implementing energy efficiency programs to mitigate demand growth, or investing in new generating capacity. Within the category of investing in new generating capacity they are able to select amongst a set of generating technologies and energy sources. Uncertainty about future conditions that could impact the profitability of these different investment options means that retaining flexibility to react to future conditions and choose the most profitable investments has value to firms. The value associated with retaining flexibility and being able to select the most profitable investments in the future is referred to as "option value."[145] This rule does not impose a direct cost on firms by requiring them to take a specific action, instead the cost of this rule for firms is the lost option value associated with losing the ability to build a new fossil steam or combustion turbine EGU with an emissions rate above their respective standards.

This option value is determined, in part, by the likelihood that the restricted choices would have been exercised in the future absent the policy and the cost of available substitutes. Since the analysis in Chapter 4 estimates that new combustion turbines forecast in the baselinethat meet the applicability criteria will already meet the standards this discussion focuses on new fossil steam EGUs. As discussed in Chapter 4, it is highly unlikely that over the analysis period there will be enough expansion in relative fuel prices (e.g., natural gas prices relative to coal) to make a typical new fossil steam EGU cost competitive with available substitutes (e.g., NGCC, investing in energy efficiency program). Even in the unlikely event that this occurs, the incremental cost of constructing a compliant fossil steam EGU with partial CCS or an alternative compliance pathway will represent an upper bound on the costs to the firm due to the availability of substitute generation sources which might be able to provide a similar service at a lower cost. Given both of these reasons, the low likelihood of the restricted options being exercised in the baseline and availability of cost effective substitutes, on average the lost option value for firms is likely to be small.

Furthermore, as shown in the preceding sections, even when conditions arise where it is known with certainty that an outlying firm would find it most profitable to invest in a new non-compliant unit EGU over available alternatives in the baseline, the social benefits of restricting the choice set may outweighs the costs to the firm. Therefore it will also be the case that expected social benefits from preventing new EGUs with an emissions rate above the respective standards, will likely outweigh the lost option value.

A similar perspective may be applied to assessing the social costs of this rule. There are at least two notable differences when assessing the lost option value from society's perspective relative to the firm's perspective. First, from society's perspective the cost is lower because the available substitution possibilities may be greater for society than for a single firm as they are not bound by the conditions of a single firm but activities that may be pursued by all electricity producers and consumers at large. Second, the benefits of adding a single new EGU for the purpose of diversifying the generation fleet across fuels to hedge against uncertainty in fuel markets, will likely be lower for society at large than for a single firm with a generating fleet

[145] We refer the interested reader to Dixit and Pindyck (1994) and Trigeorgis (1996) for more information on the concept of option value in the context of firms' investment choices.

that is relatively less coal-intensive than the entirety of the generating fleet.[146] Both of these differences suggest that the cost of lost option value from a social perspective is lower than what is already likely to a minimal cost of lost option value for a particular firm.

It is difficult to precisely estimate the lost option value associated with this final rule given the numerous sources of uncertainty that influence investment decisions in the electricity sector and the existing modeling tools. However, the analysis reported in this chapter and the previous chapter has considered important variables that influence investment decisions in the electricity sector and found that across a wide range of potential outcomes this rule would have negligible costs. Furthermore, considering the additional analysis in this chapter and the discussion above, the cost of the lost option value of the rule is concluded to be small. Additionally, if conditions arise that would have led to the construction of non-compliant EGUs absent the final rule, the quantifiable monetized social benefits of limiting the construction of those units likely exceeds the cost (even though not all social benefits are captured). However, as discussed throughout this RIA, when considering the most likely outcomes, the new source standards are anticipated to yield no quantified benefits and impose negligible costs over the analysis period.

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[146] The option value associated with constructing a new EGU associated with a specific fuel source as part of a portfolio to hedge against uncertainty in future relative fuel prices will be conditional upon the current composition of the firm's generation portfolio. If the current stock was constructed in expectation of relative fuel prices that more strongly favored higher emitting fuels, then the composition of the generating fleet may already be too heavily weighted toward the ability to use those fuels, given the current expected distribution of relative fuel prices. Furthermore, the possibility to hedge against changes in fuel prices may be pursued by other means, such as risk contracts, and thus is not limited to the construction of generation sources with particular fuel sources.

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CHAPTER 6
MODIFIED AND RECONSTRUCTED SOURCE IMPACTS

6.1 Introduction

In addition to the standards for new sources analyzed in Chapter 4 and Chapter 5, this action also sets standards under Clean Air Act Section 111(b) for units that modify or reconstruct. For the reasons discussed in this chapter, the EPA also believes that the standards for modified and reconstructed fossil fuel-fired EGUs will result in minimal compliance costs, because we expect few 111(b) modified or reconstructed EGUs in the period of analysis (through 2022).

6.2 Reconstructed Sources

The new source performance standard (NSPS) provisions (40 CFR part 60, subpart A) define a "reconstruction" as the replacement of components of an existing facility to an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards. Historically, we are only aware of one EGU that has notified the EPA that it has reconstructed under the reconstruction provision of section 111(b). As a result, we anticipate that few EGUs will undertake reconstruction in the period of analysis. For this reason, the standards will not result in any significant emission reductions, costs, or quantified benefits in the period of analysis. Likewise, the EPA does not anticipate any impacts on the price of electricity or energy supply. The rule is not expected to raise any resource adequacy concerns, since reserve margins will not be impacted and the rule does not impose any additional requirements on existing facilities not triggering the reconstruction provision. There are no notable macroeconomic or employment impacts expected as a result of these standards.

Due to the extremely limited data available on reconstructions, it is not possible to conduct a representative illustrative analysis of what costs and benefits might result from this rule in the unlikely case that a unit were to reconstruct.

6.3 Modified Sources

Historically, few EGUs have notified the EPA that they have modified under the modification provision of section 111(b). The EPA's current regulations define an NSPS "modification" as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, but specifically exempt from that definition projects that entail the installation of pollution control equipment or systems.

The EPA expects that most of the actions EGUs are likely to take in the foreseeable future that could be classified as NSPS "modifications" would qualify as pollution control projects. In many cases, those projects are likely to involve the installation of add-on control equipment needed to meet Clean Air Act (CAA) requirements for criteria and air toxics air pollutants. Any associated carbon dioxide (CO_2) emissions increases would likely be small and would occur as a chemical byproduct of the operation of the control equipment. In other cases, those projects would involve equipment changes to improve fuel efficiency to meet state requirements for implementation of the CAA section 111(d) rulemaking for existing sources and would have the effect of increasing a source's maximum achievable hourly emission rate (lb CO_2/hr), even while decreasing its actual output based emission rate (lb CO_2/MWh). Because all of these actions would be treated as pollution control projects under the EPA's current NSPS regulations, they would be specifically exempted from the definition of modification.

Given the limited information that we have about past modifications, the EPA has concluded that it lacks sufficient information to establish standards of performance for all types of modifications at steam generating units at this time. Instead, the EPA has determined that it is appropriate to establish standards of performance at this time for large-scale modifications of steam generating units, such as major facility upgrades involving the reconstruction or replacement of steam turbines and other equipment upgrades that result in substantial increases in a unit's potential hourly CO_2 emissions rate. The EPA does not have sufficient information at this time to predict the full array of actions that existing steam generating units may undertake, including those in response to applicable requirements under an approved CAA section 111(d) plan. Additionally, it is not possible to predict which, if any, of these actions may result in increases in potential CO_2 hourly emissions. Nevertheless, the EPA expects that, to the extent actions are undertaken by existing steam generating units, the magnitude of the increases in potential hourly CO_2 emissions associated with the vast majority of such changes would generally be small and therefore would generally not be subject to the standards of performance for modified steam generating units finalized in this action.

Based on this information, we anticipate that few EGUs will take actions that would be considered NSPS modifications and subject to the standards of performance finalized in this action during the period of analysis. For this reason, the standards will result in minimal emission reductions, costs, or quantified benefits in the period of analysis. Likewise, the Agency does not anticipate any impacts on the price of electricity or energy supplies. This rule is not expected to raise any resource adequacy concerns, since reserve margins will not be impacted and the rule does not impose any additional requirements on existing facilities not triggering the NSPS modification provision. There are no notable macroeconomic or employment impacts expected as a result of these standards.

Due to the limited data available on past modifications and the diversity of existing units that could potentially modify, it is not possible to conduct a representative illustrative analysis of what costs and benefits might result from this rule in the unlikely case that a unit were to take an action that would be classified as a modification.

CHAPTER 7
STATUTORY AND EXECUTIVE ORDER REVIEWS

7.1 Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review

This final action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. It is a significant regulatory action because it raises novel legal or policy issues arising out of legal mandates. Any changes made in response to OMB recommendations have been documented in the established dockets for this action under Docket ID No. EPA-HQ-OAR-2013-0495 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units) and Docket ID No. EPA-HQ-OAR-2013-0603 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units). This RIA includes an economic analysis of the potential costs and benefits associated with this action.

The EPA does not anticipate that this final action will result in any notable compliance costs. Specifically, we believe that the standards for newly constructed fossil fuel-fired EGUs (electric utility steam generating units and natural gas-fired stationary combustion turbines) will have negligible costs associated with it over a range of likely sensitivity conditions because electric power companies will choose to build new EGUs that comply with the regulatory requirements of this action even in the absence of the action, because of existing and expected market conditions. (See Chapter 5 for further discussion of sensitivities). The EPA does not project any new coal-fired steam generating units without CCS to be built in the absence of this action. However, because some companies may choose to construct coal or other fossil fuel-fired EGUs, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired EGU with CCS. As noted previously, the monetized benefits exceed the compliance costs under a range of assumptions.

The EPA also believes that the standards for modified and reconstructed fossil fuel-fired EGUs will result in minimal compliance costs, because, as previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis (through 2022). In Chapter 6, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

7.2 Paperwork Reduction Act (PRA)

The information collection activities in this final action have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2465.03. Separate ICR documents were prepared and submitted to OMB for the proposed standards for newly constructed EGUs (EPA ICR number 2465.02) and the proposed standards for modified and reconstructed EGUs (EPA ICR number 2506.03). Because the CO_2 standards for newly constructed, modified, and reconstructed EGUs will be included in the same new subpart (40 CFR part 60, subpart TTTT) and are being finalized in the same action, the ICR document for this action includes estimates of the information collection burden on owners and operators of newly constructed, modified, and reconstructed EGUs. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data. Thus, all burden estimates are in 2013 dollars. Burden is defined at 5 CFR 1320.3(b). You can find a copy of the ICR in the dockets for this action (Docket ID Numbers EPA-HQ-OAR-2013-0495 and EPA-HQ-OAR-2013-0603), and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The recordkeeping and reporting requirements in this final action are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the Federal Register and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final action.

7.2.1 Newly constructed EGUs

This final action will impose minimal new information collection burden on owners and operators of affected newly constructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines) beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control numbers 2060-0626 and 2060-0629, respectively.Apart from certain reporting costs to comply with the emission standards under the rule, there are no new information collection costs, as the information required by the standards for newly constructed EGUs is already collected and reported by other regulatory programs.

The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any newly constructed coal-fired steam generating units that commenced construction after proposal (January 8, 2014) to commence operation over the 3-year period covered by this ICR. We estimate that 12 affected newly constructed natural gas combined cycle units and 25 affected newly constructed natural gas-fired simple-cycle combustion turbines will commence operation during that time period. As a result of this final action, owners or operators of those newly constructed units will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months.

7.2.2 Modified and Reconstructed EGUs

This final action is not expected to impose an information collection burden under the provisions of the PRA on owners and operators of affected modified and reconstructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines). As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units or stationary combustion turbines will take actions that would constitute NSPS modifications or reconstructions as defined under the EPA's NSPS regulations. Accordingly, the standards for modified and reconstructed EGUs are not anticipated to impose any information collection burden over the 3-year period covered by this ICR. We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed.

Although not anticipated, if an EGU were to modify or reconstruct, this final action would impose minimal information collection burden on those affected EGUs beyond what they would already be subject to under the authorities of CAA 40 CFR parts 75 and 98. As described above, the OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations. Apart from certain reporting costs to comply with the emission standards under the rule, there would be no new information collection costs, as the information required by the final rule is already collected and reported by other regulatory programs.

As stated above, although the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions, if an EGU were to modify or reconstruct during the 3-year period covered by this ICR, the owner or operator of the EGU will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months. The annual reporting burden for such a unit is estimated to be $1,333 and 16 labor hours. There are no annualized capital costs or O&M costs associated with burden for modified or reconstructed EGUs.

7.2.3 Information Collection Burden

The annual information collection burden for newly constructed, modified, and reconstructed EGUs consists only of reporting burden as explained above. The annual reporting burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $60,997 and 651 labor hours. There are no annualized capital costs or O&M costs associated with burden for newly constructed, modified, or reconstructed EGUs. Average burden hours per response are estimated to be 7 hours. The total number of respondents over the 3-year ICR period is estimated to be 62.

7.3 Regulatory Flexibility Act (RFA)

EPA certifies that this final action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule.

7.3.1 Newly constructed EGUs

The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built. We expect that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. We do not include an analysis of the illustrative impacts on small entities that may result from implementation of the final rule because we anticipate negligible compliance costs over a range of likely sensitivity conditions as a result of the standards for newly constructed EGUs. Thus the cost-to-sales ratios for any affected small entity would be zero costs as compared to annual sales revenue for the entity. Accordingly, there are no anticipated economic impacts as a result of the standards for newly constructed EGUs. We have therefore concluded that this final action will have no net regulatory burden for all directly regulated small entities.

7.3.2 Modified and Reconstructed EGUs

The EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification provisions in the period of analysis. An NSPS modification is defined as a physical or operational change that increases the source's maximum achievable hourly rate of emissions. The EPA does not believe that there are likely to be EGUs that will take actions that would constitute modifications as defined under the EPA's NSPS regulations.

In addition, the EPA expects few reconstructed fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines in the period of analysis. Reconstruction occurs when a single project replaces components or equipment in an existing facility and exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

In Chapter 6, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources, including any that are owned by small entities.

7.4 Unfunded Mandates Reform Act (UMRA)

This final action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

The EPA believes the final rule will have negligible compliance costs on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards.

As previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the modification or reconstruction provisions in the period of analysis. In Chapter 6, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources.

We have therefore concluded that the standards for newly constructed, modified, and reconstructed EGUs do not impose enforceable duties on any state, local or tribal governments, or the private sector, that may result in expenditures by state, local and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. We have also concluded that this action does not have regulatory requirements that might significantly or uniquely affect small governments. The threshold amount established for determining whether regulatory requirements could significantly affect small governments is $100 million annually and, as stated above, we have concluded that the final action will not result in expenditures of $100 million or more in any one year. Specifically, the EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. Further, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis.

7.5 Executive Order 13132, Federalism

This final action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few modified or reconstructed fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. We, therefore, anticipate that the final rule will impose minimal compliance costs.

7.6 Executive Order 13175, Consultation and Coordination with Indian Tribal Governments

This final action does not have tribal implications as specified in Executive Order 13175. The final rule will impose requirements on owners and operators of newly constructed, modified, and reconstructed EGUs. The EPA is aware of three facilities with coal-fired steam generating units, as well as one facility with natural gas-fired stationary combustion turbines, located in Indian Country, but is not aware of any EGUs owned or operated by tribal entities.

We note that because the rule addresses CO_2 emissions from newly constructed, modified, and reconstructed EGUs, it will affect existing EGUs such as those located at the four facilities in Indian Country only if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, the rule will neither impose substantial direct compliance costs on tribal governments nor preempt Tribal law. Accordingly, Executive Order 13175 does not apply to this action.

Nevertheless, because the EPA is aware of Tribal interest in carbon pollution standards for the power sector and, consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered consultation with tribal officials during development of this rule. Prior to the April 13, 2012 proposal (77 FR 22392), the EPA sent consultation letters to the leaders of all federally recognized tribes. Although only newly constructed, modified, and reconstructed EGUs will be affected by this action, the EPA's consultation regarded planned actions for new and existing sources. The letters provided information regarding the EPA's development of NSPS and emission guidelines for EGUs and offered consultation. A consultation/outreach meeting was held on May 23, 2011, with the Forest County Potawatomi Community, the Fond du Lac Band of Lake Superior Chippewa Reservation, and the Leech Lake Band of Ojibwe. A description of that consultation is included in the preamble to the proposed standards for new EGUs (79 FR 1501, January 8, 2014).

The EPA also offered consultation to the leaders of all federally recognized tribes after the proposed action for newly constructed EGUs was signed on September, 20, 2013. On November 1, 2013, the EPA sent letters to tribal leaders that provided information regarding the EPA's development of carbon pollution standards for new, modified, reconstructed and existing EGUs and offered consultation. No tribes requested consultation regarding the standards for newly constructed EGUs.

In addition to offering consultation, the EPA also conducted outreach to tribes during development of this rule. The EPA held a series of listening sessions prior to proposal of GHG standards for newly constructed EGUs. Tribes participated in a session on February 17, 2011, with the state agencies, as well as in a separate session with tribes on April 20, 2011. The EPA also held a series of listening sessions prior to proposal of GHG standards for modified and reconstructed EGUs and GHG emission guidelines for existing EGUs. Tribes participated in a session on September 9, 2013, together with the state agencies, as well as in a separate tribe-only session on September 26, 2013. In addition, an outreach meeting was held on September

9, 2013, with tribal representatives from some of the federally recognized tribes. The EPA also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on July 25, 2013, and December 19, 2013. Additional detail regarding this stakeholder outreach is included in the preamble to the proposed emission guidelines for existing EGUs (79 FR 34830, June 18, 2014).

7.7 Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866. While the action is not subject to Executive Order 13045, the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

CO2 is a potent greenhouse gas that contributes to climate change and is emitted in significant quantities by fossil fuel-fired power plants. As stated above, the EPA believes the final rule will have negligible effects on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA believes that the CO_2 emission reductions resulting from implementation of these final standards, as well as substantial ozone and $PM_{2.5}$ emission reductions as a co-benefit, will further improve children's health. However, Chapter 5 of this RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS. Under these scenarios, the rule would result in substantial reductions of both CO2, and also fine particulate matter such that net quantifiable benefits exceed regulatory costs under a range of scenarios. Under these same scenarios, this rule would have a positive effect for children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and lifestages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in Section II.A of the preamble.

7.8 Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This final action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, this action is not anticipated to have notable impacts on emissions, costs or energy supply decisions for the affected electric utility industry.

7.9 National Technology Transfer and Advancement Act_

This final action involves technical standards. The following voluntary consensus standards are used in the final rule: American Society for Testing and Materials (ASTM) Methods D388-12 (Standard Classification of Coals by Rank), D396-13c (Standard Specification for Fuel Oils), D975-14 (Standard Specification for Diesel Fuel Oils), D3699-13b (Standard Specification for Kerosene), D6751-12 (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), D7467-13 (Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)), and American National Standards Institute (ANSI) Standard C12.20 (American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Classes). The rule also requires use of Appendices A, B, D, F and G to 40 CFR part 75; these Appendices contain standards that have already been reviewed under the NTTAA.

7.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority or low-income populations, finding that certain parts of the population may be especially vulnerable based on their circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See Sections F and G, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence that the potential impacts of climate change raise environmental justice issues is found in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies that the potential impacts of climate change raise environmental justice issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resource within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change.

The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being. The most recent assessments continue to strengthen scientific understanding of climate change risks to minority and low-income populations in the United States.[147] The new assessment reports provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the United States. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income and some communities of color, raising environmental justice concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, the assessment reports also find that climate change poses particular threats to health, wellbeing, and ways of life of indigenous peoples in the United States.

As the scientific literature presented above and in the Endangerment Finding illustrates, low income communities and some communities of color are especially vulnerable to the health and other adverse impacts of climate change.

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[147] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, 841 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 1132 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects*. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp.

The EPA believes the human health or environmental risk addressed by this final action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The final rule limits GHG emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines by establishing national emission standards for CO_2.

The EPA has determined that the final rule will not result in disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because the rule is not anticipated to notably affect the level of protection provided to human health or the environment. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly built natural gas-fired stationary combustion turbines will meet the standards. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. This final rule will ensure that, to whatever extent there are newly constructed, modified, and reconstructed EGUs, they will use the best performing technologies to limit emissions of CO2.

7.11 Congressional Review Act (CRA)

This final action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a “major rule” as defined by 5 U.S.C. 804(2).

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